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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-04204A-09-0206 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Dr. Thomas H. Fish; David C. Parcell; W. Michael Lewis; and Kenneth C. Rozen of the Utilities Division. An Unredacted version of both Dr. Thomas H. Fish's and Kenneth C. Rozen's Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 6th day of November 2009.

Maureen A. Scott, Senior Staff Counsel
Wesley Van Cleve, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 6th day of November 2009 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
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Copies of the foregoing mailed this 6th day of November 2009 to:

Michael W. Patten
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren, Suite 800
Phoenix, Arizona 85004

Philip J. Dion
Michelle Livengood
UniSource Energy Services
One South Church Avenue
Tucson, Arizona 85701

Daniel W. Pozefsky, Chief Counsel
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

(PUBLIC)

DIRECT

TESTIMONY

OF

DR. THOMAS H. FISH

DAVID C. PARCELL

W. MICHAEL LEWIS

KENNETH C. ROZEN

DOCKET NO. E-04204A-09-0206

IN THE MATTER OF THE APPLICATION OF
UNS ELECTRIC, INC. FOR THE ESTABLISHMENT
OF JUST AND REASONABLE RATES AND CHARGES
DESIGNED TO REALIZE A REASONABLE RATE
OF RETURN ON THE FAIR VALUE OF THE PROPERTIES
OF UNS ELECTRIC, INC DEVOTED TO ITS OPERATIONS
THROUGHOUT THE STATE OF ARIZONA

NOVEMBER 06, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

(PUBLIC)

DIRECT

TESTIMONY

OF

THOMAS H. FISH, PH.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

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EXECUTIVE SUMMARY
UNS ELECTRIC INC.
DOCKET NO. E-04204A-09-0206

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data.
- Rate base
- Test year revenues
- Affiliate transactions
- Depreciation rates
- The Company's requested modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC") and Staff's proposed modification to the PPFAC
- Prudence review of the Company's PPFAC policies
- The Company's proposed ratemaking treatment for the Black Mountain Generating Station ("BMGS")

My findings and recommendations for each of these areas are as follows:

- The Company is proposing an increase in gross revenue requirement of $13,500,000 which represents a weighted average cost of capital of 10.38 percent (of which 1.34 percent is fair value adjustment). I am recommending an increase in gross revenue requirement of $7,517,565 which represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment of 1.5 percent on the increment in fair value rate base over original cost rate base).

- The following adjustments to UNS Electric's proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base		**Original Cost**	**Fair Value**
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-3	Remove post test-year plant in service	($7,263,614)	($7,263,614)
B-4	Cash working capital – lead/lag study	($61,025)	($61,025)
	Total of Staff Adjustments	($7,324,639)	($7,324,639)
	UNS Proposed Rate Base	$175,818,913	$354,485,222
	Staff Recommended Rate Base	$168,494,274	$347,160,583

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made:

Adj. No.	Description	Increase (Decrease)
C-3	Incentive Compensation PEP	($132,159)
C-4	Incentive Compensation SERP	($102,142)
C-5	Payroll Tax Expense PEP	($10,110)
C-6	Call Center Expense	($281,581)
C-7	Industry Association Dues	($40,792)
C-8	Legal Expense	($58,722)
C-9	Fuel Expense	($75,798)
C-10	Rate Case Expense	($66,667)
C-11	CARES Expense (Revenue Shortfall)	$61,797
C-12	Bad Debt Expense	($105,487)
C-13	Depr. & Property tax for Post TY PIS	($442,526)
C-2	Income Tax	$481,859
	Total of Staff Adjustments to Operating income	**$895,923**
	Company Adjusted Test Year Operating Income	$10,003,347
	Staff Adjusted Test Year Operating Income	$10,899,270

- The Company proposed technical updates to its depreciation schedules. The proposed schedules are reasonable and should be implemented.

- The Company proposed changing the PPFAC interest rate to London Interbank Offered Rate plus 1.0 percent and proposed including Credit Support Costs in PPFAC. I recommend leaving the interest rate based on the One-Year Nominal U.S. Treasury Constant Maturities Rate. This is consistent with the Commission's recent decisions regarding interest rates and will provide incentive for the Company to reduce the bank balance. I also recommend denying the request to include Credit Support Costs in PPFAC. Only Federal Energy Regulatory Commission accounts 501, 547, 555, and 565 that deal directly with fuel and purchased power costs should be included in PPFAC. I recommend that the forward component cap be updated to reflect the first year's operation of the PPFAC.

- With respect to affiliate transactions the Company is adhering to the National Association of Regulatory Utility Commissioners ("NARUC") guidelines for affiliate transactions. Based upon the information supplied by the Company, it appears they are complying with all of NARUC'S guidelines

- The Company's PPFAC policies are prudent with only minor modifications required. These include more frequent internal audits and use of Tucson Electric Power Company resources to minimize natural gas costs via pipeline availability analysis.

- The Company requested the Commission to authorize its purchase of BMGS and allow it to include the net purchase price in rate base as a post test-year plant in service adjustment. I recommend that the Commission deny this request. The Company was granted the ability to finance acquisition of the plant in its last rate case and chose not to do so. Since the Company does not own the plant now it should not be included in rate base.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business address is 1020 Fredericksburg Rd., Excelsior Springs, MO 64024.

Q. What does Ariadair Economics Group do?

A. Ariadair Economics Group provides expert witness and consulting services in administrative and judicial litigation proceedings.

Q. Please describe your educational background.

A. I hold a B.A. (1968) degree in Economics from University of Missouri at Kansas City, a M.A. (1970) degree in Economics from Central Missouri State University, and a Ph.D. (1972) degree in Economics, with minor areas of study in Finance and Marketing, from University of Arkansas.

Q. Please describe your professional experience.

A. I have provided expert witness and consulting services in Economics, Finance, Utility Regulation, Industrial Organization, and related areas in administrative and judicial litigation proceedings for over thirty years. I have also taught graduate and undergraduate college classes in Economics, Finance, Quantitative Methods, Financial Accounting, Managerial Accounting, Cost Accounting, Management and related classes.

I have provided expert testimony in a wide array of utility regulation proceedings regarding many issues. In addition, I recently provided testimony regarding Revenue Requirement and certain adjustments to Revenue Requirement, Original Cost Rate Base ("OCRB"), Reconstruction Cost New ("RCN"), and Fair Value Rate Base ("FVRB"), Cost of Service ("COS"), Revenue Spread and Rate Design in the UNS Gas proceeding (Docket No. G-04204A-08-0571). UNS Gas is an affiliate of UNS Electric, Inc. My resume is attached as Attachment THF – 1.

Q. What is the purpose of your testimony in this case?

A. I have been directed by the Utilities Division of the Arizona Corporation Commission ("Staff") to review the rate application of UNS Electric, Inc. ("Company" or "UNSE") and to address the following issues: Revenue Requirement and certain adjustments to Revenue Requirement, OCRB, Reconstruction Cost New Depreciation ("RCND"), FVRB; Purchased Power and Fuel Adjustment Clause ("PPFAC"); Review of the Black Mountain Generating Station ("BMGS"); Review of affiliate transactions between the Company, UniSource Energy, and its other affiliates; Analysis of the appropriateness of the proposed depreciation schedules; and a Prudence Review of Fuel and Purchased Power Policy.

Q. Have you reviewed the Company's application for rate relief?

A. Yes. I have reviewed, analyzed and evaluated the Company's application, its proposed rate base, revenue requirement, pro forma adjustments, work papers in support of its pro forma adjustments, and its responses to data requests submitted by Staff and other participants in the proceeding. I have also visited the Company's BMGS plant in Kingman and its Valencia plant in Nogales as well as its Tucson Offices where I met and interviewed Company personnel regarding the above-mentioned issues.

The Company currently provides electric service to approximately 90,000 customers in Arizona. Staff's review of Consumer Services records indicates that UNS Electric had 408 Complaints, 300 Inquiries and 89 Opinions between January 1, 2006 and November

5, 2009. Except for one Complaint, all recorded issues have been fully resolved. Further, the Company is in good standing with the Corporations Division of the Commission.

Q. Have you prepared Attachments and Schedules in support of your testimony?

A. Yes, I have prepared the following:

Attachment	Topic
THF - 1	Thomas Fish Resume
THF - 2	A, B, and C Schedules

Q. Please explain the Attachment THF - 2 Schedules.

A. The A, B, and C Schedules are associated with the rate base/revenue requirement part of my testimony. They are largely consistent with the corresponding Company Application Schedules A, B, and C.

Q. Would you describe the THF A-1 Schedule?

A. The THF A-1 Schedule summarizes the results of my analysis of the Company's rate request. It presents the Company's proposed OCRB, RCND, and FVRB from the Company's A Schedules and Staff's OCRB, RCND, and FVRB from Staff Schedules THF B-1 and THF C-1. It also provides a summary of operating income, rate of return, required return, required operating income, operating income deficiency, and increase in gross revenue requirement as requested by the Company and recommended by Staff.

Q. Would you describe the THF B Schedules?

A. These are Schedules showing derivation of Staff's OCRB, RCND, and FVRB. Schedule THF B-1 provides a summary of the adjustments to OCRB and RCN rate bases and the resulting FVRB for Company and Staff. The adjustments for Schedule THF B-1 are derived from Schedule THF B-2. Schedule THF B-2 presents the individual Staff adjustments to OCRB. Since, as discussed in detail below, test year values for OCRB and RCND for expenditures made and expenses incurred during the test year are the same, an additional Schedule for the adjustments for RCND is not required. Staff has made two pro forma adjustments to OCRB and RCND rate base. These are removal of the Company's proposed Post-Test Year Plant in Service adjustment and Working Capital Adjustment. The Working Capital Adjustment is necessary to adjust Cash Working Capital requirement for pro forma income and expense adjustments made by Staff. This is shown in Schedule THF B-3. Removal of the Company's Post-Test Year Plant in Service adjustment is shown in Schedule THF B-4.

Q. Would you describe your THF C Schedules?

A. The test-year income statement is shown in Schedule C-1. This Schedule presents adjustments to the Company's proposed Test Year Income Statement that are summarized on Schedule THF C-2 and then used for Schedule THF C-1. Schedule THF C-2 provides a summary of the individual income and expense pro forma adjustments made by Staff. These individual Schedules are show in Schedules THF C-3 through THF C-13.

Q. Were these Schedules prepared by you or under your supervision?

A. Yes.

Q. Would you provide an overview of the process involved in identifying the Company's revenue requirement?

A. The Company's rate base, capital, revenues and operating expenses for the test year are determined from its books and records. Then necessary pro forma adjustments are made to rate base, capital, revenues and operating expenses, to reflect values that can reasonably be expected to occur over a normal or representative year (the test year). The Company is provided the opportunity to recover its cost of service and earn a return on capital investment (rate base). The required return on capital committed to the enterprise is determined via a financial and economic analysis. In this case Mr. Parcell conducted the cost of capital analysis.

Q. Would you explain the concept of test year?

A. Yes. The cost of providing service is determined on the basis of a test year. A test year reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that are expected to exist when the resulting rates are in effect.

Q. What test year did the Company use?

A. The Company used a historic test year ending December 31, 2008.

Q. How is the cost of providing service determined?

A. Regulated utilities such as UNS Electric should be provided the opportunity to recover their cost of providing service, including an opportunity to recover their capital cost. Rates for utility services are set by utility regulators, in this case the Arizona Corporation Commission, so that utilities have an opportunity to recover these costs incurred in the provision of service. This determination is made with reference to a normal, representative, or test year.

Q. What is required to determine the proper, or representative, level of expense, revenues, and investment?

A. In a rate proceeding, test year rate base, revenues and expenses are evaluated and necessary adjustments are made to reflect values that are representatives of cost of service, on an on-going basis. Some rate base items such as plant in service and accumulated depreciation are based on end of test year levels. Other rate base items such as materials and supplies are based on a test year average level. Certain expense items such as payroll and payroll tax expense are annualized. Expense items that have been incurred, but are not necessary for the provision of service, are removed from the test year. In addition, some expense items, such as legal expense, may occur on ongoing but irregular intervals and require adjusting to normal levels. So some items may require no adjustments, some may require removal, some may require annualization and some may require normalization. After all these adjustments have been made, test year operating income is compared to required operating income and, if a shortfall exists, rates are set to provide the utility the opportunity to recover its cost of service and earn its authorized rate of return.

REVENUE REQUIREMENT

Q. What revenue increase has UNS Electric requested?

A. UNS Electric requested an increase in revenues of $13,500,000 or about an 8.5 percent increase over test year revenue.

Q. What are the reasons given for the requested increase in revenues?

A. According to Company witness DeConcini, there are three reasons for the request: (1) the Company's rate base has grown significantly; (2) the Company's operating costs have increased; and (3) its return on equity has deteriorated substantially.

Q. Does Staff agree with the Company's request?

A. Staff has some disagreements with certain adjustments the Company made and with certain adjustments the Company did not make. Staff's finding and recommendations are presented in the THF A, THF B, and THF C Schedules.

Q. What revenue increase does Staff recommend?

A. As shown on Schedule THF A-1, Staff has identified an operating income deficiency of $4,574,216 and is recommending an increase in gross revenue requirement of $7,517,565 or about 4.7 percent over test year revenue.

Q. Did Staff determine a Fair Value Rate of Return and its application to FVRB?

A. Yes. The Commission's traditional calculation of return on FVRB calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

The Court of Appeals determined at pages 13-24, paragraph 17, that ". . . the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." Further, at page 13, "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

In Decision No. 70441, Docket No. W-02113A-04-0616, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including the weighted average cost of capital to exclude the effect of inflation on the cost of equity, and that the FVROR adopted fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

Mr. Parcell addressed the cost of capital issue and developed a range of return on fair value rate base. The range determined by Mr. Parcell was 0 percent to 3 percent return on the increment between OCRB and FVRB. I have used the first moment about the mean, or mathematical expectation, of 1.5 percent to derive the return on FVRB as presented in Schedule A-1. This mid-point value was recommended by Mr. Parcell and represents a reasonable estimate of the fair value return.

Q. Other than rate of return, what are the major sources of the difference between the Company's request and Staff's recommendation?

A. The differences are as follows (the Staff values represent pro forma changes from Company proposed values. These are pro forma adjustments to rate base and operating income and are discussed in detail later in the testimony. The remainder of the difference between Company and Staff relates to cost of capital. This issue is addressed by Staff witness Parcell.

	Company Request	Staff
RATE BASE		
Post Test Year PIS	+$7,263,614	Remove
Working Capital		-$61,025

PRO FORMA INCOME AND EXPENSE

Incentive Compensation PEP	-$132,159
Incentive Compensation SERP	-$102,142
Payroll Tax Expense PEP	-$10,110
Call Center Expense	-$281,582
Industry Association Dues	-$40,792
Legal Expense	-$58,722
Fuel Expense	-$75,798
Rate Case Expense	-$66,667
CARES Expense (Revenue shortfall)	$61,797
Bad Debt Expense	-$105,487
Depr. & Prop tax for Post TY PIS	-$442,526
Income Tax	$481,859

RATE BASE

Q. Would you explain the regulatory concept of rate base?

A. Yes. Regulated utilities are provided the opportunity to recover the cost of the capital used to create the plant necessary to provide service. The capital cost is determined by multiplying the rate base (roughly equal to its capital structure) by the regulated utility's cost of capital (in percentage terms). The Arizona Corporation Commission rules require UNS Electric to file an OCRB and a RCND rate base. In addition, the Company's FVRB must be considered by the Commission in rendering its decision.

Q. What is an Original Cost Rate Base?

A. According to the Commission's definition[1] an OCRB is an amount consisting of the depreciated original cost, prudently invested, of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used or useful, plus a proper allowance for working capital and including applicable pro forma adjustments.

Q. What is a RCN Rate Base?

A. According to the Commission's definition[2] a RCN Rate Base is an amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments.

Q. What is a Fair Value Rate Base?

A. A FVRB, as accepted and used by the Commission, is the arithmetic mean of the OCRB and RCND Rate Base.

Orignal Cost Rate Base

Introduction

Q. What was the Company's proposed OCRB?

A. The Company proposed a total OCRB of $164,679,539. This was based on gross utility plant in service of $454,177,170. Gross utility plant in service was adjusted by accumulated depreciation, Citizens Acquisition Discount, Accumulated Amortization of Citizens Acquisition Discount, Customer Advances for Construction, Customer Deposits, and Allowance for Working Capital. These adjustments to gross utility plant in service generated the adjusted OCRB.

[1] Title 14, Public Service Corporations, page 7 of 159.
[2] Ibid.

Q. Did the Company propose any pro forma adjustments to OCRB?

A. Yes. The Company proposed adjustments for Post Test-Year Plant in Service, Accumulated Deferred Income Taxes, and Working Capital.

Q. What was the adjusted OCRB proposed by the Company?

A. The Company's proposed adjusted OCRB was $175, 818,913.

Q. Are you proposing any pro forma adjustments to the Company's proposed adjusted OCRB?

A. Yes. I am proposing two adjustments to the Company's proposed OCRB and RCND rate base. My adjustments related to: 1) Post Test Year Non-Revenue Plant in Service and 2) Working Capital.

Post Test-Year Non-Revenue Producing Plant in Service

Q. What pro forma adjustment for post test-year plant in service did the Company propose?

A. The Company proposed to increase test year OCRB (and RCND) by $7,263,615 of post test year plant.

Q. What was the reason given by the Company for this pro forma adjustment?

A. According to Company Witness Dallas Dukes:

> "The Commission should allow UNS Electric to recover such costs. UNS Electric made these investments to serve existing customers. UNS Electric will not begin recovering on these investments until the time the investments are reflected in rate base within a rate proceeding. Including post test year non-revenue producing plant in rate base will allow UNS Electric to recover its investment and an opportunity at (sic) earn a reasonable return in a timely manner. If this current case follows an expected course, new rates will go into effect in June 2010 at the

> earliest. The Company's next rate case will likely not be filed until April of 2011, with rates most likely not effective until June 2012. So the recovery of and on investments actually made before the end of the 2008, but not technically in service, will not produce additional revenues until June 2012. In other words, without this adjustment, UNS Electric would not begin recovering its investment for over 3 ½ years after the investments were made to serve existing customers." (Dukes Prepared Direct Testimony, page 12, lines 10 - 21.)

Q. Do you agree with Mr. Dukes' justification for inclusion of post test year plant in service in rate base?

A. No. Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce costs of providing service such as maintenance cost. This could result in a mismatch between post-test year revenue and costs. In addition, the Company has a choice as to when it files an application for rate relief. The Company could have waited to file its application so as to include this investment in its test year. Further, over time the Company will have depreciated its rate base that exists at the end of the test year and retired some of those assets. Rates, however, will continue to reflect the test year values for those assets. This is a benefit ignored by the Company which offsets some of the difficulties cited by Mr. Dukes.

Q. Did the Company provide adequate evidence that the proposed post test-year plant in service adjustment is revenue neutral?

A. No. Company witness Dukes testified that the proposed adjustment was revenue neutral and the work papers supporting the adjustment stated that the proposed adjustment was revenue neutral. He did not, however, provide any studies or analyses that supported that contention, either in aggregate or line item basis.

Q. Does Staff believe the proposed post test year plant is revenue neutral?

A. No. Staff has no basis to make that determination. Staff would suspect that investments are made to either reduce costs or generate revenue or both. Absent any evidence to the contrary, Staff does not accept the Company's revenue neutrality proposal.

Q. Has the Commission permitted utilities to include post test year plant in service in rate base in the past?

A. Yes.

Q. Did you review any of the Decisions where the Commission permitted utilities to include post test year plant in service in rate base?

A. Yes. I have reviewed several decisions where the Commission permitted Post test year plant in Service to be included in rate base. These were Decision Nos. 65350, 66849, 67279, 68176 and 68864. These decisions were referred to by Mr. Dukes in his rebuttal testimony regarding his proposed post test-year plant in service pro forma adjustment in the recent UNS Gas case.

Q. In Decision No. 65350 what did the Commission determine with respect to post test-year plant in service?

A. In Docket No. 01-0776, Bella Vista Water Company had made a series of capital investments that were in service after the end of the test year but prior to the hearing. The investment at issue amounted to about 24 percent of rate base and was installed to enhance service to existing customers and to increase system reliability. A reason given by the Commission to allow the plant to be included in rate base was that it did not want to discourage companies from proactively addressing system reliability needs and thus incur another rate case expense. In addition, the Commission agreed with Staff that the Company had the burden to demonstrate that the post test-year plant is revenue neutral.

Q. In Decision No. 66849 what did the Commission determine with respect to Post Test-Year Plant in Service in that Case?

A. In Docket No. 02-0619 Arizona Water Company sought inclusion of $3,349,416 of post test-year plant in service in rate base. Staff and the Company agreed that post test-year plant in service was consistent with pro forma adjustments related to post-test year plant additions. The Commission determined that the Company's pro forma adjustments were correct and allowed the post test-year plant in service to be included in rate base.

Q. In Decision No. 67279 what did the Commission decide with respect to Post Test-Year Plant in Service?

A. In Docket No. 03-0434, Rio Rico Utilities proposed an OCRB of $2,462,446 for water utility plant and $4,136,931 for wastewater utility plant. These included adjustments for post test-year plant additions totaling $595,657 of water utility plant and $293,417 for wastewater utility plant. The Commission allowed the post test-year waste water plant in service to be included in rate base because the plant was in service when Staff inspected it, the new wastewater plant was the replacement for a Lift Station and was not an upsize, and was required because the Company had been experiencing breakages and spills with the old force main. The water utility post test-year plant in service was a 12 inch main and a booster plant. The Commission allowed this post test-year plant to be included in rate base because customers had been complaining of low water pressure.

Q. In Decision No. 68176 what did the Commission decide with respect to post test-year plant in service in that Decision?

A. In Docket No. 04-0616, Chaparral City Water Company proposed $42,538,338 for OCRB. Of that amount, $2,979,239 represented plant additions placed in service after the test year: $2,038,443 for the expansion of a water treatment plant, and $940,979 related to a transmission main. The Commission permitted inclusion of the water treatment plant in rate base. The Commission determined that the water treatment plant allows the Company to reliably meet peak demands during the summer months with CAP water while retaining the ability to take individual modules off line for repairs and to meet emergency needs. Absent the investment the Company had been operating with minimal flexibility for routine maintenance and repairs and had no operating safety margin in the event of a need to shut down some of its treatment facilities. The Commission allowed the cost of the main in rate base because it provided operational flexibility and improved service to customers.

Q. In Decision No. 68864 what did the Commission decide with respect to the issue of post test-year plant in service?

A. In Docket No. 05-0873 Tortolita Water Company reported a rate base of $61,787, comprised of net plant in service. Staff reduced total rate base of old plant that was no longer used or useful by $60,331, to $1,457 and allowed post-test year contributed plant of $381,919. Post test-year plant was treated as contributed plant and net rate base of $1,457 was included in working capital.

Q. What factors did the utilities in these proceedings have in common?

A. Generally, the Post test year plant was large relative to the rate base, the specific capital items were especially important for the provision of safe and reliable service, and factors which caused the delay in completion of plant past test year end were extraordinary.

Q. Does UNS Electric have a similar situation with respect to the capital items it wishes to include in rate base in this proceeding?

A. No. The total of the capital items requested to be included in rate base is less than 4.2% of adjusted original cost rate base. The capital items appear to consist of projects that are normal and on-going for electric utilities. Finally, the Company did not point to any specific factors that prevented the completion of any of the projects beyond the end of the test year.

Q. Did you prepare a Schedule showing this pro forma rate base adjustment?

A. Yes. The adjustment is shown in Schedule THF B-4 and carried over to Schedule THF B-2.

Q. What is Staff's recommendation regarding this issue?

A. Staff recommends that the Commission reject the Company's request to have these capital investments included in rate base as a post test-year plant in service adjustment. The reasons, as discussed above, include the small size of the investments relative to the Company's rate base, the relatively non-essential, or on-going, nature of the investments, and the lack of support for the revenue neutrality contention.

Working Capital

Q. Did you review the Company's proposed Working Capital pro forma adjustment?

A. Yes.

Q. What are the components of Working Capital?

A. Working Capital is composed of Materials and Supplies, Prepayments, and Cash Working Capital. The Company's calculated values for these components are: ($2,810,346) for cash working capital; $8,261,763 for materials and supplies; and $634,351 for Prepayments.

Q. Are you proposing any adjustments in these Working Capital components?

A. Yes. I am proposing a pro forma adjustment to cash working capital. This adjustment is necessary as a result of the proposed pro forma adjustments to income and expenses. The adjustment includes a minor correction in the Company's cash working capital calculation.[3] The pro forma adjustment to working capital is $61,025.

Q. Did you prepare a Schedule showing this pro forma adjustment to rate base?

A. Yes. The pro forma adjustment is shown on Schedule THF B-3 and is carried over to Schedule THF B-2.

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[3] In Company Schedule B5 row 15 (property taxes) the lead lag factor, column F, is incorrectly calculated as (.4848) and should be (.4861). This results in a total cash working capital of ($2,814,811) rather than the ($2,810,346) shown on the Schedule. The net effect is a change of ($4,465) and is included in Staff's pro forma adjustment as a consequence of correcting the lead lag factor.

RCND Rate Base

Introduction

Q. What was the Company's proposed RCND Rate Base?

A. The Company proposed a total RCND Rate Base of $337,180,792. This was based on gross utility plant in service of $837,037,541. Gross utility plant in service was adjusted by accumulated depreciation, Citizens Acquisition Discount, Accumulated Amortization of Citizens Acquisition Discount, Customer Advances for Construction, Customer Deposits, and Allowance for Working Capital. These adjustments to gross utility plant in service generated the adjusted rate base.

Q. Did the Company propose any pro forma adjustments to RCND rate base?

A. Yes. The Company proposed adjustments for post test-year plant in service, Accumulated Deferred Income Taxes, and Working Capital.

Q. What was the adjusted RCND rate base proposed by the Company?

A. The Company's proposed adjusted RCND Rate Base was $354,485,222.

RCND Derivation

Q. Would you provide an overview of the process of deriving a RCND rate base?

A. Yes. A RCND study is a point in time measurement, just as an original cost rate base is a point in time measurement. That is, the Company's RCND rate base today most likely will not have the same value as the RCND rate base as of December 31, 2008. Rate Base Income Statement measurements are over time, or flow measurements.

Q What information does the RCND Rate Base convey?

A The RCND rate base provides the gross value of the rate base is a balance sheet idea and balance sheet values are point in time measurements while expressed in today's dollars, and the RCND rate base provides the net value of the rate base expressed in today's dollars. A properly constructed RCND rate base provides an estimate of what the cost would be to reconstruct the existing rate base if it were to be constructed now in today's dollars.

Q. Are there underlying assumptions of RCND studies?

A. Yes. An underlying assumption of RCND studies is that the value of a dollar today, everything else being equal, has more value than a dollar to be received in the future and that a dollar received in the past, everything else being equal, has more value than a dollar to be received now. So the RCND rate base is the value of the rate base when all net dollars invested have the same value regardless of when they were invested. The Original Cost rate base is the value of the rate base when all net dollars have the specific value of those dollars at the time they were spent, that is, they are not adjusted for changes in the value of the dollars. The way to convert current dollars into constant (value) dollars is to create a price (or cost) index for the various types of investments and use the price (or cost) index to convert to constant dollars.

Q. What is a price, or cost, index?

A. Index values provide a relative comparison of prices or costs over time. Price or cost indices have a base period where the index value is 100 and observations away from the base have different values based upon the value of the dollars at those observations. For the RCND rate base derivation we want the base period to be the test year. That is, we want to conduct the analysis in today's dollars because the RCND will show us how much we would have to spend, in today's dollars, to duplicate the rate base that currently exists. The primary source of index values used in RCND calculations is the Handy-Whitman construction cost index by geographic location and Federal Energy Regulatory Commission ("FERC") account.

Q. Please describe the Handy-Whitman cost indices.

A. The Handy-Whitman indices are index values of plant and equipment costs by FERC account and by region. They have a base value (100) early on in the time series so we need to convert the base from the earlier base period of the series to the end of test year observation. This conversion process is one of dividing the end of test year index by each individual index throughout the series.

RCND Example

Q. Can you give an example of this?

A. Yes. Consider the following example where we are converting the base period from year one in the original index to year four in a new index:

Year	Original index value	Conversion equation	New Index value
1	100.00	(130/100)*100	130.00
2	110.00	(130/110)*100	118.18
3	120.00	(130/120)*100	108.33
4	130.00	(130/130)*100	100.00

Note that the "New Index value" series has the same relative values between the years as does the Original index value series. However, the indices are measured with respect to year 4 values rather than with respect to year 1 values. The conversion of the base period demonstrated above shown under the column headed "New Index Value" corresponds to the Company's term "Trend Value" used in its RCND study.

This process is simply one of changing the base period but not the relative values of the observations between periods. In the example above, the base period was changed from year one to year four.

Q. Are there any unusual characteristics about values calculated using this technique?

A. Yes. By definition, the RCND values for the test year will be the same as the Original Cost values for the test year.

Q. Can you please briefly explain the difference?

A. Yes. The base period always has an index value of 100 which means that current and constant dollars are the same and the base period for RCND studies for regulatory purposes is the test year. This equality that exists in the base period will only occur if the index values for previous, (or subsequent) periods are exactly equal to the base period index value. This will rarely, if ever, be the case.

Q. Does this feature of the construction of RCND rate base have implications for determining the validity of the resulting RCND rate base?

A. Yes. If a pro forma adjustment to the Original Cost rate base and the corresponding pro forma adjustment to the RCND rate base for an expenditure during the test year have different values, then there was an inconsistency in constructing the RCND rate base.

Pro Forma RCND Rate Base Adjustments

Q. Did you make any pro forma adjustments to the Company's RCND rate base?

A. The adjustments made to the OCRB discussed above are also directly applicable to the Company's RCND Rate Base. The reason for this is because the values for OCRB and RCND Rate Base are the same for the base, or test year. Therefore the OCRB adjustments apply to the RCND Rate Base. That is the adjustments made in Schedules THF B-2, THF B-3, and THF B-4 apply to both rate bases.

FairValue Rate Base

Introduction

Q. What is the procedure for deriving FVRB?

A. Fair Value Rate Base is derived by calculating the average of the OCRB and RCND Rate Base, which the Commission has adopted in the past.

FVRB Derivation

Q. What was the Company's proposed FVRB?

A. The Company's proposed FVRB is $265,152,067. This is the average of the OCRB and RCND Rate Base.

Q. What is Staff's FVRB?

A. Staff's FVRB is $257,827,428.

Q. Did UNS Electric or Staff make adjustments to FVRB?

A. No. The adjustments were made to OCRB and RCND Rate Base so they were included in FVRB indirectly.

OPERATING INCOME ADJUSTMENTS

Q. Do you provide Schedules summarizing your pro forma adjustments to operating income?

A. Yes. Schedule THF C-1 provides a summary of Adjusted Net Operating Income and Schedule THF C-2 provides a summary of pro forma Income Statement Adjustments. The sections below provide a discussion of the pro forma adjustments to Operating Income.

Incentive Compensation and Executive Comp/Benefits (SERP and PEP)

Q. Please explain your pro forma adjustments for incentive compensation and Executive Compensation/Benefits.

A. This program provides retirement benefits to eligible executives in excess of the limits allowed under Internal Revenue Service regulations. In its last rate case the Commission disallowed certain incentive compensation and Supplemental Executive Retirement expenses. For various reasons the Commission decided to disallow 50 percent of certain incentive program costs and 100 percent of Supplemental Executive Retirement Plan costs. The Commission determined that the Performance Enhancement Plan ("PEP") program benefited both ratepayers and owners equally and allowed for ratepayers to pay for one half the cost and for owners to pay the other half. Supplemental Executive Retirement Plan ("SERP"), on the other hand, is a retirement program for high income employees. The Commission did not determine that the Company could not or should not offer this program, only that ratepayers should not be expected to fund it.

Q. What do you recommend with respect to SERP and PEP incentive compensation?

A. Since both Company stock holders and rate payers benefit from PEP incentive compensation I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP-related incentive compensation. The PEP pro forma adjustment is shown in Schedule THF C-3 and is one half of the total PEP costs, or $132,158.

Schedule THF C-4 shows the pro forma adjustment for SERP-related expenses. I am recommending that the Commission disallow all $102,142 of SERP related expenses in this proceeding for the same reasons that it disallowed these expenses in the previous UNS Electric case, that is, if the Company wishes to reward its top executives with high levels of retirement benefits, then, since Company owners benefit, owners should shoulder the burden. The Company identified this SERP-related expense amount in its lead lag study.

Payroll Tax Expense (SERP/PEP)

Q. What is your payroll tax expense pro forma adjustment?

A. The Payroll Tax Expense is related to the PEP incentive pay adjustment. Since I am recommending disallowance of certain PEP related expenses, the payroll taxes associated with those expenses should also be disallowed.

Q. Have you prepared a Schedule showing this pro forma adjustment?

A. Schedule THF C-5 shows this pro forma adjustment. Since the PEP incentive pay adjustment is $132,158 the payroll tax expense associated with this amount should also be disallowed. The estimated minimal payroll tax expense is 7.65 percent of the PEP incentive pro forma adjustment, or $10,110.

Call Center

Q. What is the Call Center?

A. The Call Center is a central location that all UNS Electric, UNS Gas and TEP customers can contact for utility-related matters. By using a single call center wasteful duplication of resources and expenses can be avoided. The three companies share in the expense of the Call Center.

Q. Please explain the Call Center expense.

A. The total test year Call Center charge to UNS Electric was $880,533. In the last rate case, the Company had increased its Call Center costs from $532,154 when it operated its Call Center on a stand-alone basis to $598,951 after the call center operations were consolidated.[4] In Decision No. 70360 the Commission allowed the Company to recover the full amount of Call Center Expenses incurred. The Commission gave two reasons for its determination: First, there had been a significant increase in call volume since the Call Center operations had consolidated; and second, on a stand-alone basis the Call Center would have required additional investment.

Q. What are the benefits to UNS Electric's customers of the Call Center?

A. According to Company witness McKenna at pages 7 – 8 of his Direct Testimony there are several benefits arising from the Call Center. First, it is open five days a week from 7 a.m. to 7 p.m. The customer service representatives can handle a wide range of transactions including service connection, service disconnection, account balance information, payment arrangements, and outage reporting. In addition, the Call Center offers "Virtual Hold" which provides customers the opportunity to remain in line for a representative or to hang up and have the Call Center call back.

Q. With all of these services available, has the call volume increased?

A. No. Call volume has decreased. According to Mr. McKenna call volume was down by 15 percent.

[4] From RUCO witness Moore Schedule RLM-14, Page 1 of 1 in Docket No. E-04204A-06-0783.

Q. Did the Company provide information as to why Call Center volume has decreased by 15 percent?

A. No. It would appear, however, that the Call Center may have been designed for a much larger volume of calls than exists.

Q. What do you recommend with respect to Call Center expenses?

A. I recommend that the Company not be permitted to recover the increase in Call Center expense since the last rate case. A reason given by the Commission in the last rate case to allow recovery of the increase in Call Center expense was increased volume of calls. That reason no longer exists. Therefore I am proposing a pro forma adjustment. I am recommending that the Commission disallow the increase of $281,582. Unless the Company can show that the increased Call Center expense resulted in savings elsewhere, and that customers have benefited by this increase in cost, the Commission should not permit this increase.

Q. Have you prepared a Schedule showing this pro forma adjustment?

A. Yes. I present my Call Center pro forma adjustment in Schedule THF C-6.

Industry Association Dues

Q. Do the Company's ratepayers benefit by the Company's membership in professional organizations?

A. There would clearly appear to be some benefit provided to ratepayers as a result of membership in professional organizations. The Company and its ratepayers can expect to enjoy the benefits of joint research and certain member services. However, there are also organizational activities that most likely do not benefit ratepayers.

Q. What might those activities be?

A. Such things as Utility Air Regulatory Group ("UARG") dues, legislative advocacy, regulatory advocacy, advertising, marketing, and public relations.

Q. Did UNS Electric propose a pro forma adjustment for its Industry Association dues?

A. No.

Q. What did the Commission decide in the last rate case with respect to Industry Association dues?

A. In its last rate case the Commission in Decision No. 70360 disallowed 49.93 percent of EEI dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations (at page 26).

Q. Are you proposing a pro forma adjustment with respect to Industry Association dues in this proceeding?

A. Yes.

Q. What is the basis for your proposed pro forma adjustment?

A. I am proposing that the proportion of dues not related to activities that are not necessary for the provision of service to UNSE customers be disallowed.

Q. Have you prepared a Schedule showing your calculation of this pro forma adjustment?

A. Yes. This is shown on Schedule THF C-7.

Outside Legal Expenses

Q. Does the Company incur outside legal expenses in the normal operation of its business activities?

A. Yes. The Company, like all business, will, from time to time, require outside legal assistance.

Q. Should the Company be allowed to recover its reasonable cost of outside legal assistance?

A. Yes.

Q. Is the Company requesting recovery of its cost of outside legal assistance?

A. Yes.

Q. Are you proposing a pro forma adjustment to legal expenses?

A. Yes. The Company made a pro forma adjustment of $109,433.80 for legal expense and included it in its miscellaneous expense pro forma adjustment. An evaluation of this outside legal assistance expense suggests that the amount includes non-representative expenses. Therefore, Staff made its pro forma adjustment and reduced the Company proposed adjustment by ($58,722), as shown in Schedule THF C-8.

Q How did you calculate this pro forma adjustment?

A. As shown in Schedule THF C-8, the Company included, $180,906, for 2007 in its calculation of three-year average. Staff removed that amount from the calculation and used the allowable amount of $28,830 for 2008 to calculate its three year average. The correct three-year average is $87,572 and the difference in the calculated amounts by Staff and Company is the amount of the pro forma adjustment.

Q. What do you recommend with respect to outside legal expenses?

A. I recommend that the Commission reduce the Company's proposed outside legal expense amount by $58,722. The reason that this adjustment is required is that the Company is using a non-representative value ($180,906 for 2007) in its efforts to derive a normalized outside legal expense amount. The non-representative 2007 legal expense amount causes the three-year average to be overstated. The proper value to use in calculating the three-year average is the 2008 amount.

Fleet Fuel Expense

Q. Does the Company incur an expense for fuel for its fleet of vehicles?

A. Yes.

Q. Is this a legitimate cost of providing service that the Company should be given the opportunity to recover?

A. Yes.

Q. Is the Company proposing to recover its reasonable Fleet Fuel cost on a going forward basis?

A. No. The Company is proposing to recover costs in excess of its reasonable Fleet Fuel cost.

Q. Are you proposing a pro forma adjustment to correct for this over recovery of Fleet Fuel costs?

A. Yes.

Q. Please explain your Fleet Fuel Expense Adjustment.

A. The Fleet Fuel Expense pro forma Adjustment is presented in Schedule THF C-9. The Company experienced average price per gallon for gasoline of $3.32 and of diesel of $3.82 during its test year. Fuel prices for the first half of the test year were unusually high and the average price per gallon of fuel has dropped since the test year. Using the average of 2009 actual monthly prices to date plus the projected average monthly price for the remainder of 2009 results in an average gasoline price per gallon of $2.52 and an average diesel price per gallon of $2.65 for 2009. This is a more reasonable and realistic fuel cost than the actual test year average. I am proposing a pro forma adjustment of $75,798 for Fleet Fuel expense.

Q. What was the source of fuel cost information?

A. The source of the fuel cost information was the AAA.com web site.

Rate Case Expense

Q. Did the Company propose a pro forma rate case expense adjustment?

A. Yes. In its adjustment work papers the Company had removed $58,333 from current year activities, increased rate case expense from Decision No. 70360 by $30,556 and added $166,667 of expenses for this rate case based on rate case expenses of $500,000 for a total pro forma adjustment of $138,890.

Q. Is the Company's proposed rate expense of $500,000 reasonable?

A. No.

Q. Are you proposing a pro forma adjustment to correct the requested amount?

A. Yes.

Q. What was the basis for your adjustment?

A. In Decision No. 70360 the Commission had authorized the Company to recover rate case expense of $300,000 amortized over three years. The Commission also authorized UNS Gas to recover $300,000 rate case expenses amortized over three years in Decision No. 70011.

Q. What are you proposing?

A. The situation here is similar to those two cases. I am proposing that the Commission allow the Company to recover $300,000 in rate case expenses over three years. Therefore, I am proposing a pro forma adjustment to reduce rate case expense by $66,667. This is shown in Schedule THF C-10.

Customer Assistance Residential Energy Support ("CARES") Discounts

Q. What is the CARES program?

A. The CARES program is a pricing plan available to residential customers presently taking service under the Company's residential service pricing plan whose gross annual income is not more than one hundred fifty percent of the federal poverty level guideline effective at the time qualification and annual certification is sought. Residential customers who desire to qualify for the plan must make application to the Company for qualification and provide verification to the Company that the customer's household income does not exceed one hundred fifty percent of the federal poverty level.

Q. Did the Company propose a pro forma adjustment for CARES discounts?

A. Yes. Company witness Erdwurm sponsors a pro forma adjustment to recover $61,797 in additional test year CARES discounts.

Q. What was the basis for the proposed adjustment?

A. According to Mr. Erdwurm's work papers provided in support of the adjustment the number of CARES customers varied by month within the test year and an adjustment was required to account for the change.

Q. Do you agree with Mr. Erdwurm's proposed justification for the adjustment?

A. No. According to Mr. Erdwurm the Company made both customer and weather annualization adjustments and change within the CARES customer class would have been captured in those calculations. The proposed CARES adjustment can be expected to double recover those revenues. In addition, the Company proposed a pro forma adjustment of $52,937 in its last rate case to reflect the reduction in revenues as a result of the switch in residential customers to the CARES program. The Commission rejected that request, and I recommend this Company request be rejected.

Q. Have you prepared a Schedule in support of this pro forma adjustment?

A. Yes, Schedule THF C-11.

Bad Debt Expense

Q. Does the Company incur an expense as a result of some customers not paying for service received?

A. Yes. A certain amount of customers bills are not paid and are counted as bad debts.

Q. How are bad debts measured?

A. Normally as a percentage of sales.

Q. Does this methodology usually require a pro forma expense adjustment?

A. Yes. Changes in revenue resulting from pro forma adjustments to income and expense items may require a pro forma adjustment to properly reflect the bad debt level.

Q. Did the Company propose a pro forma adjustment for bad debt expense?

A. Yes.

Q. How did the Company calculate its bad debt pro forma adjustment?

A. The Company calculated its three-year average ratio of uncollectibles to total retail sales (0.004718) and multiplied this amount by Uncollectible Revenue Adjustment base to derive its base pro forma bad debt expense ($764,063) and subtracted that from its actual bad debt loss for the test year ($1,200,504) to derive its adjustment ($436,441).

Q. What is the basis for your proposed bad debt pro forma adjustment?

A. The Company based its ratio of uncollectibles to sales on gross sales but calculated its adjusted amount on adjusted sales. This resulted in an overstatement of the bad debt expense pro forma adjustment of $105,000. My proposed bad debt pro forma adjustment corrects for the Company mistake.

Q. Have you prepared a Schedule showing the derivation of your pro forma bad debt adjustment?

A. Yes. Schedule THF C-12 shows the calculation of this adjustment.

Depreciation and Property Tax for Post test year plantin Service

Q. Did the Company propose a pro forma adjustment of Depreciation and Property Tax as a result of its proposed Post-Test Year Plant in Service Adjustment?

A. Yes.

Q. Do you propose a pro forma adjustment for this item?

A. Yes.

Q. What is the basis for your proposed adjustment?

A. Since I am proposing to remove the Post-Test Year Plant in Service Adjustment proposed by the Company from rate base, the accompanying Depreciation and Property Tax adjustment must also be removed.

Q. Did you prepare a Schedule showing this pro forma adjustment?

A. Yes. Schedule THF C-13 shows this pro forma adjustment of ($442,526).

Income Tax

Q. Please explain your income tax adjustment.

A. This adjustment is shown on Schedule THF C-2. It reflects the income tax effect of the pro forma changes in income and expense items.

AFFILIATE TRANSACTIONS

Introduction

Q. What is the purpose of your review and evaluation of affiliate transactions?

A. To provide recommendations regarding UNS Electric's dealings with its parent company, Unisource, and its other affiliates.

Q. What is the current structure of the organization providing services to UNS Electric and its affiliates?

A. There is no separate service organization created for the provision of various affiliate services. The (regulatory-related) services appear to be primarily provided by TEP personnel on behalf of UNS Electric although there are payments made by UNS Electric on behalf of TEP. There are also Direct Costs and Indirect Costs assigned to UNS Electric. Staff had only minimal information regarding the performance and operations of unregulated affiliates,[5] because transactions between UNSE and unregulated affiliates during the time period requested were not large in number. Staff, however, has recently issued a follow up data request to the Company to confirm that Staff's understanding of its data request responses on this issue is correct. If need be, depending upon the Company's response to the Staff's follow up data request, the Staff may address this issue further in its Surrebuttal Testimony.

Q. Who are the Company's affiliates?

A. In addition to UNS Electric the following companies are owned by UniSource Energy Corporation:[6]

Advanced Energy Technologies, Inc.
Escavada Leasing Company
MEH Equities Management Company
Millennium Energy Holdings, Inc.
Millennium Environ mental Group, Inc.
Nations Energy Corporation

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[5] Most of the non-regulated affiliate information that was provided by the Company dealt with the proposed purchase of BMGS although a few transactions were between SES and UNSE.
[6] From Page 450.1 of FERC FORM NO. 1 for 2008/Q4.

San Carlos Resources, Inc.

Southwest Energy Solutions, Inc.

Tucson Electric Power Company

Tucsonel, Inc.

UniSource Energy Development Company

UniSource Energy Services, Inc.

UNS Gas, Inc.

Q. What criteria do you recommend with respect to evaluating the relations between the Company and its affiliates?

A. I recommend that the relations between the affiliates be patterned after the proposed National Association of Regulatory Utility Commissioners ("NARUC") guidelines for Cost Allocations and Affiliate Transactions.

Q. Would you summarize those guidelines?

A. Yes. In Guidelines for Cost Allocations and Affiliate Transactions the premise is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. Guidelines is composed of the following sections: A. Definitions; B. Cost Allocation Principles; C. Cost Allocation Manual (Not Tariffed); D. Affiliate Transactions (Not Tariffed); E. Audit Requirements; and, F. Reporting Requirements.

Allocations and Pricing

Q. Did the Company provide information regarding cost allocations?

A. Yes. In response to a Staff data request, STF 12.1, requesting a copy of any Cost Allocation Manuals used by the Company, its affiliates, or Unisource Energy, and all cost allocations used by the Company, any affiliate of the Company or by Unisource Energy, the Company provided purpose, costs, and basis for:

- Allocations within TEP
- Allocations within UNS Electric and UNS Gas
- Allocations across TEP, UNS Electric and UNS Gas
- Overheads on TEP Direct Charges for Labor and/or Material to UNS Electric from TEP
- Common Systems Allocations (from TEP to UNS Electric)
- Corporate Costs – "UNS Allocation" from TEP to UNS Electric

Q. Do the purpose, costs, and bases appear to be reasonable?

A. Yes. They appear to be reasonable and consistent.

Q. What is the pricing policy for services between the Company and its affiliates?

A. In response to a Staff data request, STF 12.4 the Company indicated that it first assigned costs directly where possible. Common costs were then assigned by cost causation where possible. Finally, where cost causation cannot be determined, the cost is assigned on the basis of payroll costs, plant/tangible assets, and total revenue.

Q. Is this approach consistent with the NARUC <u>Guidelines</u>?

A. Yes.

Q. With respect to your requests for information regarding affiliate transactions did the Company provide information regarding transactions involving unregulated affiliates?

A. The Company's responses dealt primarily with regulated affiliates.

Q. In your opinion do unregulated affiliates have a role in this proceeding?

A. Yes. For example, UED built BMGS and UNS Electric is requesting permission to purchase it. The prudence of the construction of the BMGS and of the purchase of BMGS from UED is important in this proceeding.

Q. Does the NARUC approach address pricing of services?

A. Yes. The affiliate transactions pricing guidelines are based on first, affiliate transactions raise the possibility of self-dealing where market forces do not necessarily drive prices and, second, utilities have an incentive to shift costs from non-regulated to regulated monopoly operations. So the objective of the affiliate transactions guidelines is to lessen the possibility for subsidization.

Q. What are the NARUC general rules for pricing?

A. According to the <u>Guidelines</u> at page 4:

1. Generally, the price for services, products and the use of assets provided by a regulatory entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

Q. Did the Company provide information showing how self-dealing is prevented and how costs are not over allocated to regulated affiliates?

A. Yes. Based upon the data I reviewed, it does appear that the Company and its affiliates are complying with NARUC's guidelines. However, we have recently sent the Company a follow up data request and I will address this issue further in my Surrebuttal Testimony if necessary.

Structure

Q. What is the current structure of UniSource Energy's service organization?

A. As noted above, there is no formal structure and most of the regulated services are provided by TEP personnel. Further, from the information received by UNSE, it appears that its transactions with unregulated affiliates is limited. From my review, allocations to UNSE are made on both direct and indirect basis.

Q. In your opinion is it beneficial to the Company's ratepayers for certain services to be provided jointly, such as call center, rather than by each Company (TEP, UNS Gas, UNS Electric) individually?

A. Yes. In my opinion total cost of service could be expected to be significantly higher if each of these types of services was provided individually as opposed to jointly.

Q. What do you recommend with respect to affiliate transactions between UNS Electric, its affiliates, and UniSource Energy as a result of your review and evaluation?

A. I recommend that the Company and its affiliates continue to comply with NARUC's guidelines on affiliate transaction. From the information I was provided, I believe the Company is in compliance.

DEPRECIATION RATES

Q. What is the purpose of your review and evaluation of the Company's proposed depreciation schedules?

A. The purpose of my review and evaluation was to provide recommendations regarding the appropriateness of UNS Electric's proposed depreciation schedules and provide revised depreciation schedules if necessary.

Q. Did the Company propose new depreciation rates in this proceeding?

A. Yes. Company witness White conducted 2009 technical updates of depreciation rates for the Company and provided testimony regarding those updates.

Q. How many updates were conducted?

A. The Company conducted two updates on its depreciation rates. One update included Black Mountain Generating Station and one update omitted BMGS.

Q. Did the Company provide the work papers and supporting documentation for the technical updates?

A. Yes. That information was evaluated and analyzed as part of the review of the proposed depreciation rates.

Q. When were the current depreciation rates approved by the Commission?

A. On May 27, 2008 in Decision No. 70360.

Q. What were the results of the technical updates?

A. According to Dr. White the accrual rate for the Company without BMGS changed from 4.24 percent for the total utility to 4.03 percent which resulted in an expense deduction of $938,358. The accrual rate for the Company with BMGS changed from 4.04 percent to 3.85 percent which resulted in an expense reduction of $927,268. The change in accrual rate and corresponding reduction in depreciation expense is the result of a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Q. Did the depreciation study address accumulated depreciation?

A. Yes. For both updates depreciation reserves were rebalanced. The computed reserve was less than the recorded reserve so computed reserves were increased to recorded reserve totals so as to maintain the new account accruals.

Q. Do you agree with the results of the study?

A. My review of the technical update and supporting documentation revealed no significant problems.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Introduction

Q. What is the purpose of your testimony with respect to the PPFAC?

A. The purpose of my testimony with respect to PPFAC is to: 1) Review the PPFAC mechanism and make recommendations regarding UNS Electric's proposed changes; 2) review the existing PPFAC mechanism and propose changes that would improve its performance; 3) calculate a new base cost of fuel and purchased power; and 4) make any necessary adjustments to the Plan of Administration.

Q. What was the scope of your review of the Company's PPFAC?

A. I reviewed the Company's pro forma adjustment work papers, responses to data requests, submitted PPFAC filings and support documentation, documents from the previous case dealing with the PPFAC, and interviews with Company officials.

Development and Operation of the PPFAC

Q. Would you describe the history of the current PPFAC?

A. Yes. Until June 1, 2008, the Company acquired its power supply through a fixed price, full requirements agreement with Pinnacle West. That agreement expired on May 31, 2008 and the Company was required to obtain a new power supply. As a result, the Company needed a modified PPFAC to recover its cost of purchased power and fuel.

Q. Did you review the Company's purchased power agreements?

A. Yes. A listing of these agreements is given in the "Fuel and Purchased Power Contracts" section of the Prudence Review of Fuel and Purchase Power Policy part of my testimony.

Q. Please describe the Company's PPFAC.

A. A PPFAC is adjustor mechanism that allows a company to recover or refund changes in purchase power and fuel costs between rate cases. UNSE's current PPFAC went into effect on June 1, 2008, and is administered under a POA, i.e., Plan of Administration. The PPFAC has a "forward component" and a "true-up component." The forward component is based on forecasted fuel and purchased power costs. The true-up component compares actual fuel and purchased power costs with the amounts collected through base rates and the PPFAC rate in the prior year. The true-up component reconciles actual and forecast fuel and purchased power costs and is incorporated into the following year's PPFAC rate. The PPFAC runs from June 1 through May 31 of the following year. The Company is required to file information and calculations showing the next year's forward and true-up components by December 31. Staff would have until February 15 to issue comments or recommended adjustments to the Company's December 31 filing. The Company would be required to file a response by April 1 and Staff would respond to that by April 15. The new rate would take effect unless the Commission suspended the PPFAC or decided to take other action. In the event of extraordinary circumstances the Company could seek a modification to the rate.

Q. What are the current PPFCA rates?

A. In Decision No. 70360 the Commission established the average base cost of Fuel and Purchased Power at $.071218 per kWh. This was the starting point on June 1, 2008 and on June 1, 2009 a new PPFAC rate was set at ($0.010564) per kWh and included a true-up component of ($.007545) per kWh.

Q. What expenses are to be recovered in the PPFAC?

A. Only expenses recorded in FERC accounts 501, 547, 555, and 565 are to be recovered in the PPFAC.

Q. Did you review the Company's expenses to verify that only allowable expenses were included in the PPFAC?

A. Yes. My review indicated that the Company had only included permissible expenses in the PPFAC.

Q. Is the Company's accounting system adequate and reasonably maintained to collect, report, and audit the PPFAC filings, and to conduct testing?

A. The Company's accounting system is audited annually through the annual audit of the Company's financial statements. In my opinion the processes in place are adequate and reasonably maintained to collect and prepare the PPFAC filings and to facilitate the conduct of testing on such filings.

Q. Did the Company propose a new average base cost of purchased power and fuel in this proceeding?

A. Yes. The Company proposed a new average base cost of $0.067738 per kWh.

Q. What was the basis for the proposed new average base cost?

A. The Company proposed three pro forma adjustments to revenue requirement. These were: Retail Revenue & Purchased Power Annualization to annualize test year revenue and expenses to reflect a full year of the previous cases rates, including PPFAC; Wholesale Revenue & Purchased Power to adjust PPFAC eligible costs to reflect the June 1, 2009 PPFAC; and, Normalization of Revenue and Expense for Fuel and Purchased Power to reduce the revenues and expenses associated with the recovery of PPFAC.

Q. Did you review the Company's derivation and calculations of the proposed new base rate?

A. Yes. Staff reviewed the derivation and calculations and does not propose a pro forma adjustment to those calculations.

Q. Has the Commission permitted such a recalculation of base rates in other proceedings?

A. Yes. In the 2007 APS case[7] the Commission permitted the Company to recalculate average base rates and in the previous UNS Electric case[8] the Commission allowed a pro forma adjustment that flowed to base rates.

[7] Decision No. 69663 at pages 31-33.
[8] Decision No. 70360 Page 33 "Valencia Turbine Fuel"

Q. Does Staff recommend that the Commission adopt the new base rate?

A. Staff recommends that the Commission adopt the Company's process for calculating the base rate but that the Commission direct the Company to true up the base rate prior to implementation.

Q. Does the current PPFAC have a cap?

A. Yes. The forward component of the PPFAC has a cap.

Q. What is the current cap?

A. The cap was set at $0.0173 per kWh in Decision No. 70360. The Commission indicated that the cap was implemented because of concerns about the potential magnitude of fuel and purchased power fluctuations.

Q. What was the magnitude of fuel and purchased power changes between June 1, 2008 and June 1, 2009?

A. The difference between base fuel costs on June 1, 2008 and on June 1, 2009 is $.01845 per kWh.

Q. Do you recommend that the cap be changed to recognize the actual experience of the PPFAC?

A. Yes. I recommend that the cap on the forward component of the PPFAC be changed to $.01845 per kWh.

Q. Will your proposed change in the cap on the forward component of the PPFAC require a change to the POA?

A. Yes. At page 3, Section 3. PPFAC, subsection 1, the value $0.0173 should be replaced by $0.01845.

Q. Did the Company propose changes to the PPFAC?

A. Yes. The Company proposed changing the PPFAC interest rate and including credit support costs as recoverable expenses in the PPFAC.

Proposed Changes to PPFAC Interest Rate

Q. What is the current PPFAC interest rate?

A. The current PPFAC interest rate is the one-year Nominal U.S. Treasury Constant Maturities rate. The rate is published in the Federal Reserve Statistical Release H.15 on the first day of each calendar year.

Q What interest rate does the Company request be applied to its PPFAC balances?

A. The Company is requesting use of the 3-month LIBOR rate plus 1 percent. The Company also requests that the rate be reset every month.

Q. Do you recommend that the Commission adopt the Company's proposed change in interest rate?

A. No.

Q. Please explain.

A. I do not agree with the Company's proposed change for two reasons. First, a higher interest rate could provide a disincentive to reduce bank balances and become less inclined to take all possible measures to reduce the cost of purchased power and fuel to its customers. Second, the Company's current interest rate is consistent with the currently authorized interest rate for both UNS Gas and Southwest Gas.

Q. What do you recommend?

A. I recommend the Commission reject the Company's proposal.

Proposed Recovery of Credit Support Costs

Q. What does the Company request with respect to Recovery of Credit Support Costs?

A. The Company is requesting to recover this cost through the PPFAC.

Q. What are Credit Support Costs?

A. These are credit costs incurred when the Company must finance temporary under-collections of fuel and purchased power costs and when it must provide credit support to wholesale counter-parties. The credit support takes the form of a letter of credit or cash deposit. The Company may be required to provide assurance to a counter-party that it will perform its obligation to purchase power or natural gas as specified by the contract.

Q. What is the magnitude of UNS Electric's credit support?

A. According to Company witness Grant the Company has had between $7m and $12m of letters of credit outstanding and $12 million to $21 million of cash collateral outstanding at any point in time since August of 2008. The annualized cost of any letter of credit is 1.15 percent of the face amount and the cost of cash collateral deposits is equal to LIBOR plus 1 percent. Interest income on the escrow account may offset a portion of the rate paid by the Company, the rate earned on escrow investments is typically lower than LIBOR and does not cover the 1.0 percent credit margin also paid by the Company. Therefore, according to Mr. Grant, a cost rate of 1.15 percent also represents a reasonable cost estimate of case collateral deposits. The Company wishes to recover this cost through PPFAC.

Q. Do you recommend that the Commission adopt the Company's proposed recovery of Credit Support Costs?

A. No.

Q. Please explain.

A. First, the costs recovered by PPFAC should be directly related to purchased power or fuel costs. The PPFAC currently does this by allowing only for recovery of expenses recorded in FERC Accounts 501, 547, 555, and 565. In its last case the Company requested that certain other costs be recovered through the PPFAC and was denied. The Commission noted that no other utility was permitted to recover such costs and could see no valid reason to depart. The same reasoning still holds. Second, the Company has another way to recover those costs. It can request recovery of credit support costs, broker's fees, legal fees and other related costs through rate cases.

Forward Component Cap

Q. In your opinion has the PPFAC been effective in its current form?

A. In my opinion the PPFAC has worked as intended. It was implemented at a time of high volatility in the energy markets and has responded to the changes in energy prices and appears to have achieved its purposes.

Q. Have you considered alternative PPFAC designs that could be implemented?

A. Yes. The PPFAC in place requires adjustment annually so the change can be dramatic. In the last case both the Company and RUCO proposed forms of 12-month moving average PPFACs. While the bank balance may have been somewhat smaller under this type of plan, the monthly change in rates due to PPFAC changes could have been substantial. The Commission stated its desire to eliminate monthly volatility in Decision No. 70360 by requiring the PPFAC to be adjusted annually rather than monthly and the current PPFAC achieves that goal. There is no assurance that a change to monthly adjustment would be superior, or equal, to the current plan.

BLACK MOUNTAIN GENERATING STATION

Introduction

Q. What is the purpose of your testimony with respect to the Black Mountain Generating Station Peaker Unit?

A. The purpose of my testimony is to review the Company's request to include BMGS in rate base via a post test-year plant in service adjustment.

Q. Who currently owns BMGS?

A. BMGS is currently owned by UFD.

Q. Is the Company requesting Commission preapproval to acquire BMGS?

A. Yes.

Q. Is it the Company's responsibility to decide when to purchase BMGS?

A. Yes. The Company's management has the responsibility to decide whether it acquires BMGS.

Q. What is the Company's request regarding BMGS?

A. The Company requests the Commission to direct it to purchase BMGS and to include it in rate base as a post test-year plant in service pro forma adjustment.

Q. Have you reviewed the Company's request?

A. Yes.

Q. What did your review consist of?

A. I submitted a series of data requests and follow-up data requests to the Company regarding the proposed acquisition of BMGS. In addition, I interviewed Company personnel on-site and at the Company's Tucson offices.

Background

Q. What events led to this request by the Company for authorization to purchase BMGS?

A. The Company had a full requirements Power Supply Agreement with Pinnacle West Capital Corporation ("PWCC" or "Pinnacle West") until May 31, 2008. All energy and ancillary services for the Company's entire load requirements were provided under the agreement. As of June 1, 2008, after that agreement ended, the Company had to obtain power through other arrangements.

Q. Did the Company have a plan in place to ensure it could provide service to its customers at the time of transition?

A. Yes. The Company prepared a Procurement Plan to ensure it had the resources and commitments to serve its load after May 31, 2008.

Q. Have you reviewed the Power Supply agreement and the Procurement Plan?

A. Yes. I requested the Power Supply Agreement, the Procurement Plan, and other documents. I received them, and have reviewed them.

Q. What did the Plan provide for?

A. The Plan provided for a mix of market power purchases, resource acquisitions, and contracts for the provision of necessary capacity, energy, and reserves to meet UNS Electric's requirements.

Q. What is the Company's current power supply?

A. According to Company witness McKenna the Company currently acquires: About 50 percent of its power through power supply contracts for load and on-peak power; a Purchase Power Agreement with UED, the current owner of BMGS and an affiliate of UNS Electric; and use of the 65MW Valencia turbine units. That is, about 25 percent of requirements are fixed price capacity purchases, and approximately 35 percent are gas indexed capacity purchases. The remaining system capacity requirements are met through the PPA with UED for BMGS power, the Valencia Generating Station, and short-term purchases. Long-term sources of power were acquired through the issuance of Requests for Proposals.

Previous Commission BMGS Considerations

Q. Has the Company previously submitted a request to the Commission regarding BMGS?

A. Yes. In its last case, E-04204A-06-0783, the Company requested authority to purchase BMGS which, at the time, was planned for construction by UED. The Company proposal in the last case was to be allowed to implement a post test-year adjustment to rate base for the BMGS. Staff opposed the Company's request because UNSE did not own the BMGS at that time and in addition the cost of the plant were not known and measureable or used and useful. The Company had merely at that time purchased the two turbine units and had not yet constructed any plant.

Q. What did the Commission decide with respect to that request?

A. The Commission agreed with Staff and RUCO and denied the request because of, among other reasons, the discussed above. The Commission noted, however, that at the time of the Order, the expiration of the tolling agreement with PWCC would occur in two weeks and commercial operation of BMGS was imminent.

Q. Did the Commission look to a possible future acquisition of BMGS by the Company?

A. Yes. The Commission stated (at page 76 of Decision No. 70360): "However, the temporal coincidence of two circumstances specific to this case, expiration of UNSE's contract with Pinnacle West two weeks from now and imminent commercial operation of the plant, is a compelling basis on which to encourage UNSE's acquisition of the BMGS." In a footnote, number 20, the Commission further observed that as of May 1, 2008, BMGS had been in operation and was producing power with performance testing scheduled the next two weeks and commercial operation scheduled for mid-May 2008.

Q. Did the Commission do anything to encourage UNS Electric's acquisition of BMGS?

A. Yes. The Commission authorized UNSE to implement an accounting order to record any and all of the Company's financial activities associated with the BMGS as if the BMGS were in rate base as of June 1, 2008. In this case the Company has made that information available as Volume 4 of its application.

Q. Did the Commission address financing of BMGS by UNSE?

A. Yes. The Commission granted UNS Electric financing authority to acquire BMGS. The Company had requested approval of a financing request of up to $40 million in new equity and up to $40 million in new debt capital. Staff agreed with the request and the Commission authorized this additional financing.

Broken Blade

Q. Has one of the turbines at the BMGS recently been damaged?

A. Yes. On my visit to the plant it was discovered that an event had occurred that had damaged one of the turbines. The event was discovered during routine maintenance inspection of the turbine. This is discussed in more detail in the testimony of Staff witness W. Michael Lewis.

Q. What was the extent of the damage?

A. At the time of my visit the extent of the damage to the turbine was not known. However, in its response to STF 15.3, the Company provided information that the cost of repair is covered under warranty and that repair of the unit would take between 6 and 8 weeks.

Q. At the time of filing this testimony is Unit 1 operational?

A. No. The Company is seeking preapproval of a unit that is not currently operational.

BMGS Recommendation

Q. Did you make any determinations as a result of your review?

A. Yes

Q. What did you determine?

A. The Company does not own BMGS now, so it should not be included in rate base as a post test year plant in service adjustment even if subsequently transferred from UED to UNSE.

Q. Did the Company have an opportunity to purchase BMGS so that it could have been included in rate base in this proceeding.

A. Yes. The Company could have purchased the plant but did not.

Q. What steps has the Company taken to acquire BMGS since Decision No. 70360?

A. To the best of my knowledge, the Company has not taken any steps to acquire BMGS since Decision No. 70360 despite encouragement from the Commission to do so.

Q. Has the Company taken any steps to seek FERC's approval to acquire BMGS?

A. To the best of my knowledge, the Company has not taken any steps to seek FERC approval.

Q. In the Decision in the Company's last rate case did the Commission authorize the necessary financing for BMGS?

A. Yes. In Decision No. 70360, the Commission encouraged the Company to acquire BMGS and authorized the Company to acquire up to $80,000,000 in new debt and equity for the financing of BMGS.

Q. Do you recommend that the Commission authorize the Company to include BMGS in rate base as a post test-year plant in service adjustment?

A. No. In its last rate case the Commission provided the Company the financing capability to purchase the plant. The Company chose not to do so. Therefore, since the Company does not own the plant, it should not be included in rate base.

PRUDENCE REVIEW OF FUEL AND PURCHASED POWER POLICY

Introduction

Q. Did Staff direct you to perform a prudence review of UNS Electric's Fuel and Purchased Power policies?

A. Yes.

Q. How does the Company currently acquire power?

A. The Company has: (1) entered into power supply contracts for base load and on-peak power for 50 percent of its energy requirements; (2) uses its four turbines with a total generating capacity of 65MW at the Valencia Substation in Santa Cruz County; and (3) entered into a Purchase Power Agreement with UniSource Energy Development Company for power from Black Mountain Generating Station.

Q. Describe the Company's power supply contracts.

A. About 25 percent of requirements are fixed price capacity purchases, and about 35 percent are gas indexed capacity purchases. The remaining requirements are met through: the PPA with UED to provide power from BMGS; the Valencia Generating Station; and short-term purchases.

Q. How did you conduct your review?

A. The first step was to issue a series of data requests dealing with specific tasks of the review. Throughout the review as the Company responded to data requests additional requests were submitted concerning areas highlighted by previous responses. Next was on-site inspections of the generating units (Valencia and BMGS) and interviews with Company employees at Kingman, Nogales, and Tucson. Overall, the Company was forthcoming and responsive to the requirements of the review.

The review was broken down into the following components:

- Organization, Staffing, and Controls.
- Fuel Management.
- Fuel and Purchased Power Contracts.
- Hedging and Risk Management.
- Forecasting and Modeling.
- Plant Operations.
- Purchased Power and Off-System Sales.
- Conclusions and Recommendations

Each of the components is discussed in the following sections.

Organization, Staffing, and Controls

Q. What areas did you investigate with respect to Organization, Staffing, and Controls?

A. I investigated the following areas:

- The skills and experience of members of the fuel and procurement work groups.
- The job descriptions under which members work and verification that job descriptions match work effort.

- Access by members to appropriate training.
- The adequacy of procedures and decision processes.
- The sufficiency of the documentation of decisions.
- Procedures for acceptance of offers for gas supply.

Q. What are the procedures for approval of fuel and purchased power procurement policy and procurement transactions?

A. The Risk Management Committee is responsible for reviewing and approving the UNS Electric Fuel and Wholesale Power Hedging Policy. The Committee members are Kevin Larson, Michael DeConcini, Karen Kissinger, Raymond Heyman, David Hutchens, and Kentton Grant.

Q. What were the skills and experience of members of the fuel and procurement work groups?

A. The Company provided resumes of thirteen employees, including Mr. Michael A. Bowling who is the Supervisor, Energy Supply. The employees are well qualified and experienced for the positions they currently hold. The members are employees of TEP that provide the service through affiliate services to UNSE. UNSE is billed via affiliate transaction billing.

Q. What were the results of your review of the job descriptions under which members work and verification that job descriptions match work effort?

A. Their skills and experience match the job description requirements.

Q. What were the results of your evaluation of access by members to appropriate training?

A. Members had access to appropriate training. The training goals and objectives were well laid out and clear. Individual member quantitative and qualitative objectives were presented and tied to training.

Q. What were the results of your analysis of the adequacy of procedures and decision processes?

A. The procedures and decision processes were laid out in detail along with the key controls in the [redacted] The report provided necessary checks and balances to maintain the integrity of the procedures and decision processes.

Q. What were the results of your evaluation of the sufficiency of the documentation of decisions?

A. The sufficiency of the documentation of decisions is provided by the procedures and decision processes. The documentation is thorough with procedures for verification of real time bookouts, approval of discretionary purchases, midterm trades, and other decisions described.

Q. What were the results of your review of procedures for acceptance of offers for gas supply?

A. Natural gas is purchased and scheduled by UNS Gas for the Valencia plant. Transportation is via UNS Gas Pricing Plan T-2, Transportation Service Using Dedicated Transmission Facilities. Gas is purchased and scheduled by UNS Gas for the BMGS in accordance with the "Interruptible Gas Sales Agreement between UNS Gas and UNS

Electric." Gas is transported on the UNS Gas distribution system in accordance with the "Gas Transportation Agreement between UNS Gas and UNS Electric."

Q. What do you conclude as a result of your investigation?

A. I conclude that the Organization, Staffing, and Controls functions of UNSE's PPFAC policy are reasonable and operate as intended.

Fuel Management.

Q. What areas of investigation did you conduct with respect to Fuel Management?

A. I investigated the management of fuel inventory levels, variance analysis, measurement of supplier performance, and analysis of current supplier rate structure with respect to natural gas/diesel fuel.

Q. What did your evaluation of management of fuel inventory levels, variance analysis, measurement of supplier performance, and analysis of current supplier rate structure with respect to natural gas/diesel fuel reveal?

A. There are no coal or natural gas inventories, so the only fuel inventories are those of diesel fuel which is a backup to natural gas for three Valencia turbines. The current inventory level of #2 diesel for use in the Units 1, 2, and 3 is 35,000 gallons and is replenished as needed. Variance analyses and supplier performance measurements are not conducted.

Q. What do you conclude as a result of your investigation?

A. Because of the nature of the Company's system, inventory controls and management are limited to number 2 diesel. The Company's procedures for fuel inventory control are adequate.

Fuel and Purchased Power Contracts.

Q. **Does the Company have a Procurement Plan that it follows with respect to Purchased Power and Fuel?**

A. Yes. In its previous case the Company created and submitted a detailed Procurement Plan to insure it had the necessary resources and contracts to reliably serve its load after expiration of the Pinnacle West Capital Corporation ("PWCC") contract on May 31, 2008.

Q. **Did you review the Plan?**

A. Yes.

Q. **Would you summarize the Plan?**

A. Yes. The Plan examined the existing load, resource mix, and projected future growth. It examined a group of recommended products, how the product purchases would be facilitated and a schedule for purchase. It also covered various credit and accounting treatment considerations which are associated with the future resource needs of UNSE.

Q. **Did you review the Company's Fuel and Purchased Power Contracts?**

A. Yes. I reviewed the following contracts:

[redacted]

[redacted]

[redacted]

Q. Would you provide an overview of the Gas Swaps and Power Contracts used by the Company?

A. UNS Electric enters into forward contracts to purchase a specified amount of capacity or energy at a specified price for a given period of time, within established limits, to reduce exposure to energy price risk associated with their gas and purchased power requirements to serve retail load, volumetric risk associated with their seasonal load, and operational risk associated with their power plants and transmission systems. UNS Electric also has natural gas supply agreements under which it purchases all of its gas requirements at spot market prices. These positions, by themselves, are risky. So to minimize the risk associated with these purchases the Company enters into gas price swap agreements under which they purchase gas at fixed prices and simultaneously sell gas at spot market prices. The contracts are subject to specified risk parameters established and monitored by the Company's Risk Management Committee.

Q. Does the Company utilize periodic internal and external audits on the procurement of fuel and purchased power?

A. No. According to Mr. DeConcini there were no internal audit reports issued in 2007 or 2008 related to the procurement of fuel and purchased power.[9]

Q. Even though no audit reports were issued in 2007 and 2008 are there additional safeguards regarding prices paid for purchased power?

A. Yes. UNS Electric obtains a significant amount of its long-term energy requirements through Request for Proposal solicitations. The RFP process is overseen by an Independent Monitor. In addition, the Company purchases short-term energy through power brokers that match buyers and sellers in the wholesale market. Hourly energy is obtained primarily through TEP and is priced at the Four Corners Daily Index.

Hedging and Risk Management.

Q. Have you reviewed the Company's hedging activities?

A. Yes.

Q. Are there any constraints regarding the amount of hedging activity?

A. Yes. According to Mr. Michael Bowling at a minimum, 45 percent of the forecasted monthly energy requirements are hedged before the beginning of each month. The Company may purchase additional energy, not to exceed 75 percent of the forecasted energy requirements. Purchases of both natural gas and power are made monthly over a three-year period prior to the month of their delivery for use. Purchasing or dispatching units for the balance of their needs has the effect of "cost averaging" the price of fuel and purchased power.[10]

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[9] See Company response to STF 3.135
[10] See response to STF 4.4

Q. What type of hedging instruments have been used by the Company in 2008 and 2009?

A. The Company has used: 1) Firm, fixed price physical power; 2) firm, gas indexed physical power; 3) financial swaps; 4) financial collars; and 5) balance of the month physical power.

Q. How does the Company choose between alternative hedging strategies?

A. According to Mr. DeConcini the Company uses physical power to hedge its forward power risk so that the capacity risk is managed by the same mechanism that limits price risk. Although the Company could use financial power purchases, those purchases would ultimately require financial to physical swaps for physical delivery. When market heat rates are at acceptable level and liquidity for such products is available the company uses gas-indexed forward power. When hedging gas, the Company uses financial swing products because the actual physical gas is supplied by UNS Gas. When hedging, UNS Electric is hedging price risk through the use of fixed price financial swing gas.

Q. Are these types of hedging instruments appropriate for its purchased power and fuel procurement requirements?

A. Yes.

Q. Does the Company use outside hedging consultants?

A. No.

Q. What procedures are in place to assure that hedging operations are not used to speculate?

A. The Company requires adherence to its established hedging policies which prohibits speculation and has no incentive programs tied to trading activities. Purchased power and purchased fuel are the only material hedging participated in and any benefits from this hedging are passed directly to customers though the PPFAC.

Forecasting and Modeling.

Q. Does the Company rely on forecasts of fuel and purchased power volume requirements?

A. Yes.

Q. How does the Company develop forecasts of fuel and purchased power volume requirements?

A. The Company used a production cost model called Planning and Risk. It is built around a chronological unit commitment model that produces optimized unit and market-based dispatch results. An Excel workbook that outlines fuel costs and subsequent unit dispatch costs to determine correct dispatch of resources is used for day-ahead and real time traders. The workbook is updated daily with current market fuel prices.

Q. Does the Company use modeling with respect to demand and load forecasts?

A. Yes. The Company projects load and load demand for at least fifteen years. The forecasts are for Company total and individual customer classes and locations.

Q. Did you review the models and output?

A. Yes. The models appear to be stable and comprehensive. The statistics associated with the output are strong.

Purchased Power and Off-System Sales.

Q. Did you review the Company's purchased power and off-system sales?

A. Yes. I visited the Company's purchased power and fuel operations in Tucson and met with personnel.

Q. Did the Company have significant purchased power and off system sales?

A. The Company had significant purchased power [redacted] and a relatively small amount of off system sales [redacted].

Q. What are the Derivative Instrument Assets used by the Company?

A. Gas Swaps and Power contracts.

Q. How does the Company account for these contracts?

A. According to Company witness Kissinger the Derivative Instrument Assets are assigned to FERC Account 14460 Subacct 1110 for Derivatives-Gas Swaps and FERC Account 14460 Subacct 1100 for Derivatives-Power Contracts. The Derivative Instrument Liabilities are assigned to FERC Account 24200 Subacct 1110 for Derivatives-Gas Swaps and FERC Account 24200 Subacct 1100 for Derivatives-Power Contracts. These are short-term accounts and represent the portion of the contracts that will settle to the PPFAC Bank within twelve months of the reporting dates.[11]

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[11] See Company response to STF 1.55.

The movement and magnitude of the values of the derivatives is a function of derivative volumes and forward price curves used in marked-to-market calculations. Gas swap derivatives are valued using NYMEX pricing, adjusted for basin differences. Power contracts are valued using aggregate pricing service or published prices when available. Published prices are not always available because of the local and regional character of power markets. When this occurs certain management assumptions are required. The Company uses assumptions regarding historical price curve relationships to calendar year quotes, apply percentage multipliers to value non-standard time blocks, and including adjustments for transmission and line losses to value contracts at illiquid delivery points.

Q. In your opinion are the techniques used by the Company to mark-to-market reasonable?

A. Yes.

Q. As part of your review did you consider the consistency with which the least-cost dispatch guidelines are conducted?

A. Yes. The resource stack consists of hedged purchases, generation resources (BMGS and Valencia units) and the market. Hedged purchases are dispatched first, followed by the next least cost resource. The determination is made using a dispatch spreadsheet. Therefore, the least-cost dispatch is consistent and efficient.

Q. Did the Company handle purchased power and off-system sales adequately?

A. Yes.

Conclusions

Q. Would you summarize your conclusions regarding your review of UNSE's Fuel and Purchased Power policies?

A. Yes. My conclusions are as follows:

1. Personnel in the fuel and power procurement area have strong skills and sufficient experience to meet their responsibilities and objectives.
2. Job descriptions match job requirements.
3. Communications within the operations area are adequate and sufficient as are communication along management levels.
4. Personnel are adequately trained and cross trained.
5. Training and compliance monitoring is adequate.
6. The relationship between fuel contract management and procurement could be strengthened.
7. Documentation of fuel and power procurement is satisfactory.
8. Internal auditing procedures are inadequate.
9. Procedures for accepting gas supply offers are adequate.
10. Trading management extends to the Board of Directors level with Directors serving on the supervisory committee.
11. Risk management procedures are extensive and sound and are incorporated with hedging policies.
12. Fuel management is primarily natural gas except for back-up diesel for Valencia units and that is reasonable.
13. The Company uses a sound policy for gas commodity.
14. The hedging program is sound.

15. The hedging program effectively considers trade offs between cost and allowing costs to fall.
16. Segregation of utility and non-utility activities is adequate.
17. Modeling to predict fuel and purchased power volume and cost is sufficiently accurate.
18. An appropriate least cost dispatch model is used.
19. Documentation is adequate for regulatory oversight.
20. The performance metrics of BMGS and Valencia demonstrate effective operation.
21. The acquisition process for purchased power is adequate.
22. Electric power trading is conducted in accordance with the goal of achieving least-cost dispatch.

Recommendations

Q. What are your recommendations regarding your review of UNSE's Fuel and Purchased Power policies?

A. My recommendations are as follows:

1. Strengthen the relationship between fuel contract management and procurement.
2. Create internal auditing procedures for contract management and procurement.
3. The analysis of possible excess interstate pipeline capacity optimization by UNS Gas should be extended to UNS Electric fuel procurement.
4. Hedging for gas procurement for August, September, and October should be considered but not required. The price of risk associated with hurricane season should be explicitly considered.

Q. Does that conclude your testimony?

A. Yes.

SCHEDULES

Schedules Accompanying
The Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
THF-1	Attachment 1, Resume of Thomas H. Fish. Ph.D.
THF-2	Attachment 2, Revenue Requirement Schedules
	Revenue Requirement
THF A-1	Computation of Increase in Gross Revenue Requirement
	Rate Base
THF B-1	Original Cost, RCND, and Fair Value Rate Base
THF B-2	Pro Forma Adjustments to Original Cost Rate Base
THF B-3	Lead/Lag Study Results
THF B-4	Post Test Year Plant in Service
	Operating Income Adjustments
THF C-1	Adjusted Test Year Income
THF C-2	Income Pro Forma Adjustments
THF C-3	Incentive Compensation-PEP
THF C-4	Incentive Compensation-SERP
THF C-5	Payroll Tax Expense
THF C-6	Call Center Expense
THF C-7	Industry Association Dues
THF C-8	Legal Expenses
THF C-9	Fleet Fuel Expense
THF C-10	Rate Case Expense
THF C-11	CARES
THF C-12	Bad Debt Expense
THF C-13	Depreciation and Property Tax, Post Test Year PIS

Curriculum Vitae

Thomas H. Fish, PhD
Tfish@ariadaireconomics.com

ADDRESS/PHONE

1020 Fredericksburg Rd.
Excelsior Springs, MO 64024
(816) 630-0628
email: tfish@ariadaireconomics.com

EDUCATION

University of Arkansas Ph.D., 1972, Major: Economics. Minors: Marketing/Management, Finance, and Quantitative Methods.

Central Missouri State University, 1970, Warrensburg: MA, Economics

University of Missouri - Kansas City, 1969, Kansas City BA, Economics

EXPERIENCE

Administrative proceedings – participated in over 80 proceedings involving economics, statistics, accounting, finance, market structure and industrial organization issues in telecommunications, electric, and oil and natural gas distribution industries.

Managerial experience – Over 20 years experience in managing private businesses. Experience in personnel, economics, market research, finance, accounting, and operations management. Managed technical departments in several firms and was group manager in many major projects.

Judicial proceedings – participated in over 70 proceedings involving antitrust, contract damages, insurance defense, economic loss, market structure and performance, and other related economics/statistics/finance issues.

Other engagements – participated in over 75 private industry and governmental engagements involving economics, market structure, statistics, finance, and operational issues.

Teaching Experience –Through July, 2003 Professor of Business and Economics at William Jewell College. Duties included teaching classes in Economics, Finance, Quantitative Methods, and Management.

Taught classes at Webster University, Avila College, and Longview Metropolitan College on an adjunct basis between 1984 and 1997. Taught graduate and undergraduate classes in the areas of Management, Marketing, Financial Accounting, Finance, Statistics, Quantitative Methods, and Economics.

Experience

1981-1986 Regulatory Consulting and Expert Witness Services. Ariadair Economics Group. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1986-1987 Directory, Economics Department, LMSL Consultants, Overland Park, Kansas. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1987-Present Judicial and Administrative litigation consultant and expert witness, Ariadair Economics Group. Regulatory consulting and the regulatory experience led to a large number of utility antitrust and related litigation engagements in addition to regulatory Commission and Consumer Advocate regulatory engagements. During the period 1981 -2000 taught on an adjunct basis at local colleges including Avila University and Webster University. During the period 1981-1999 had Consumer Advocate clients in Arizona, Nevada, Illinois, Ohio, Pennsylvania and Maine. Also during this period had Commission clients in Nebraska, Oklahoma, Tennessee, Pennsylvania, Missouri, and South Dakota,

2001-2006 Full Professor of Business and Economics at William Jewell College, Liberty, Mo. During this period also had several judicial litigation engagements involving asset valuation and economic loss..

PUBLICATIONS

"An Analysis of Valuation of Community Bank Stocks." Quarterly Community Bank Journal, April, 1983.

"An Analysis of Trends in Prices of Community Bank Control Sales." Quarterly Community Bank Journal, July, 1983.

"An Analysis of Publicly Traded Multi-Bank Holding Company Market Performance After Acquisition of Community Banks." Quarterly Community Bank Journal, October, 1983.

"Derivation of a Valuation Index for Community Bank Control Sales." Quarterly Community Bank Journal, January, 1984.

RESEARCH

Professional Presentation

"An Econometric Model of Missouri." Presented at the Missouri Valley Economic Association, 1974.

Consulting Research

Economic Impact of Various Utility Rate Structures on State and Regional Economies.

Demographic Analysis of Economic Regions.

Determination of Market Characteristics and Parameters for Jet Aircraft Manufacturing Firms.

Determination of Optimal Refinancing and Capital Structuring and Corresponding Cost of Capital and Return for Acquisitions and Mergers.

An Econometric Analysis of NECPA Pricing Policies.

An Econometric Analysis of the Effect of the Proposed 15% Severance Tax (Senate Bill #892) on the Economy of the State of Kansas.

Curtailment of Demand Econometric Model for Cincinnati Bell Telephone Company's Service Area.

Development of Control Procedures for Large Construction Projects.

Development of Automatic Bill of Materials Systems of Manufacturing Processes.

Development of Planning and Forecasting Models.

Utilization of Economic Analysis in Business Decision-Making Situations (Seminar).

A Long-Term Forecast of Relative Costs of Alternative Energy Sources.

Analysis of the Validity of Sampling Procedures for Determination of the Growth Component of the DCF Model.

Analysis of the Relative Risk of Customer Classes of Electric Companies.

Development of EDP Models for Determining Optimal Price, Financing Strategy, and Expected Return for Corporate Acquisitions and Mergers.

Analysis of Asset Valuation in Bankruptcy Cases.

Preparation of Bank Charter Applications and Supporting Economic/Demographic Analyses.

COLLEGES COURSE TAUGHT

Management

Bank Management
Financial Management
Global Issues in Business
Human Resource Management
International Business Management
Introduction to Business
Introduction to Management
Marketing Research
Organization and Management
Organizational Behavior
Small Business Management
Strategic Management
Telecommunications Management

Finance

Financial Management
Intermediate Finance
International Finance
Portfolio Selection
Principles of Finance
Readings in Finance
Seminar in Finance I
Seminar in Finance II

Quantitative Methods

Business Math
Econometrics I
Econometrics II
Quantitative Analysis I
Quantitative Analysis II
Statistics I
Statistics II

Computer Information Systems/Information Technology

Computer Applications in Business

IT Systems Analysis and Design
Systems Analysis and Design I
Systems Analysis and Design II

Economics

Advanced Microeconomics
Business Cycles and Forecasting
Current Issues in Economics
Econometrics I
Econometrics II
Fiscal Policy
Industrial Organization
Intermediate Macroeconomics
Intermediate Microeconomics
International Economics
Macroeconomics
Managerial Economics
Microeconomics
Money and Banking
Principles of Econ I
Principles of Econ II
Readings in Economics

Financial Accounting

Cost Accounting
Federal Income Tax
Financial Accounting I
Financial Accounting II
Intermediate Financial Accounting
Managerial Accounting

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Computation of Increase in Gross Revenue Requirements
Test Year Ended December 31, 2008

THF 2 (ATTACHMENT 2)

Schedule THF A-1
Page 1

Line No.	Description	(a) Company Original Cost	(b) Staff Original Cost	(c) Company RCND	(d) Staff RCND	(e) Company Fair Value	(f) Staff Fair Value	Line No.
1	Adjusted Rate Base	$175,818,913	$168,494,273	$354,485,222	$347,160,583	$265,152,067	$257,827,428	1
2	Adjusted Operating Income	$10,003,347	$10,899,270	$10,003,347	$10,899,270	$10,003,347	$10,899,270	2
3	Current Rate of Return (2/1)	5.69%	6.47%	2.82%	3.14%	3.77%	4.23%	3
4	Required Operating Income Plus Fair Value (Line 6)	$18,253,668	$14,153,519 $15,493,516	$18,253,668	$14,153,519 $15,493,516	$18,253,668	$14,153,519 $15,493,516	4
5	Weighted Average Cost of Capital	9.04%	8.40%	9.04%	4.08%	9.04%	5.49%	5
6	Fair Value Adjustment*	1.34%	$1,339,997	-3.89%	$1,339,997	-2.16%	$1,339,997	6
7	Required Rate of Return	10.38%		5.15%		6.88%		7
8	Operating Income Deficiency	$8,250,321	$4,594,246	$8,250,321	$4,594,246	$8,250,321	$4,594,246	8
9	Gross Revenue Conversion Factor	1.6363	1.6363	1.6363	1.6363	1.6363	1.6363	9
10	Increase in Gross Revenue Requirement	$13,500,000	$7,517,565	$13,500,000	$7,517,565	$13,500,000	$7,517,565	10

Supporting Schedules
Columns (a), (c), and (e) Company Schedule A-1
Line 1, columes b, d, & f From Staff Schedule THF B-1
Line 2, columes b, d, & f From Staff Schedule THF C-1

* Staff fair value adjustment is equal to Staff witness Parcel Fair Value return midpoint (0% -3%, or 1.5%) x difference between fair value and original cost rate base

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Original Cost and Adjusted RCND Rate Base
Test Year Ended December 31, 2008

Schedule THF B-1
Page 1

Line No.	Description	(a) Company Adjusted Original Cost Rate Base	(b) OCRB Staff Adjustments	(c) OCRB as Adjusted by Staff	(d) Company RCND	(e)* RCND Staff Adjustments	(f) RCND as Adjusted by Staff	(g)** Company Fair Value Rate Base	(h)** Staff Fair Value Rate Base	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	$844,301,155	$7,263,614	$837,037,541	$649,239,162	$641,975,548	1
									$0	
2	Less: Accumulated Depreciation	193,348,359	0	$193,348,359	$367,590,759	$0	$367,590,759	$280,469,559	$280,469,559	2
3	Net Utility Plant in Service	260,828,810	7,263,614	$253,565,196	$476,710,396	$7,263,614	$469,446,782	$368,769,603	$361,505,989	3
4	Citizens Acquisition Discount	(93,273,341)	0	($93,273,341)	($130,469,005)	$0	($130,469,005)	($111,871,173)	($111,871,173)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	($20,876,317)	($27,773,948)	$0	($27,773,948)	($24,325,132)	($24,325,132)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	($72,397,024)	($102,695,057)	$0	($102,695,057)	($87,546,041)	($87,546,041)	6
7	Total Net Utility Plant	188,431,786	7,263,614	$181,168,172	$374,015,339	$7,263,614	$366,751,725	$281,223,563	$273,959,949	7
									$0	
8	Customer Advances for Construction	(12,605,744)	0	($12,605,744)	($17,555,056)	$0	($17,555,056)	($15,080,400)	($15,080,400)	8
9	Customer Deposits	(4,064,671)	0	($4,064,671)	($4,064,671)	$0	($4,064,671)	($4,064,671)	($4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	($2,028,227)	($3,996,158)	$0	($3,996,158)	($3,012,192)	($3,012,192)	10
11	Total Deductions	(18,698,641)	0	($18,698,641)	($25,615,885)	$0	($25,615,885)	($22,157,263)	($22,157,263)	11
12	Allowance for Working Capital	6,085,768	61,025	$6,024,743	$6,085,768	$61,025	$6,024,743	$6,085,768	$6,024,743	12
13	Regulatory Assets	0	0	$0	0	0	0	0	0	13
14	Regulatory Liabilities	0	0	0	0	0	0	0	0	14
									0	
15	Total Rate Base	$175,818,913	$7,324,639	$168,494,273	$354,485,222	$7,324,639	$347,160,583	$265,152,067	$257,827,428	15

Supporting Schedules
Column A and D from Company filing
Column B and E from THF B-2
*For Column (e) test year OCRB and RCND adjustments have the same value for Post test year PIS and Working Capital so no separate THF B-2 equivalent Schedule is required for RCND
**Fair Value rate base, columns (g) and (h) are derived as an average of OCRB and RCND

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Actual End of TY	(b) Staff Adjustments (a)	(c) Staff Adjusted at End of TY	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	1
2	Less: Accumulated Depreciation	193,348,359	0	193,348,359	2
3	Net Utility Plant in Service	260,828,811	7,263,614	253,565,197	3
4	Citizens Acquisition Discount	(93,273,341)	0	(93,273,341)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	(20,876,317)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	(72,397,024)	6
7	Total Net Utility Plant	188,431,787	7,263,614	181,168,173	7
8	Customer Advances for Construction	(12,605,744)	0	(12,605,744)	8
9	Customer Deposits	(4,064,671)	0	(4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	(2,028,227)	10
11	Total Deductions	(18,698,642)	0	(18,698,642)	11
12	Allowance for Working Capital	6,085,768	61,025	6,024,743	12
13	Regulatory Assets	0	0	0	13
14	Regulatory Liabilities	0	0	0	14
15	Total Original Cost Rate Base	$175,818,913	$7,324,639	$168,494,274	15

Supporting Schedules
(a) B-2,Pg. 2

Recap Schedules
B-1

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	Post-Test Year Non-Revenue Plant in Service	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$7,263,614		$7,263,614	1
2	Less: Accumulated Depreciation				2
3	Net Utility Plant in Service	7,263,614		7,263,614	3
4	Citizens Acquisition Discount				4
5	Less: Accum. Amort. - Citizens Acq. Discount				5
6	Net Citizens Acquisition Discount				6
7	Total Net Utility Plant	7,263,614		7,263,614	7
8	Customer Advances for Construction				8
9	Customer Deposits				9
10	Accumulated Deferred Income Taxes				10
11	Total Deductions				11
12	Allowance for Working Capital		$61,025	61,025	12
13	Regulatory Assets				13
14	Regulatory Liabilities				14
15	Total Original Cost Rate Base	$7,263,614	$61,025	$7,324,639	15

Supporting Schedules
B3, B4

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Lead/Lag Study
Test Year Ended December 31, 2008

Description	FERC	Pro Forma Test Year Amount	Adjustment	Adjusted Amount	Ref (1)	Revenue Lag Days	Expense Lag Days	Lag Days (Col. E - Col. F)	Lead/Lag Factor (Col. H/365)	Capital Required (Col. G X Col.B)
(A)		(B)	(C)	(D)		(E)	(F)	(G)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 764,063	$ 105,487	658,576	THF C-12					$ -
Depreciation	403/404	17,810,236	313,599	17,496,637	THF C-13					-
Amortization	406	(3,575,014)	-	(3,575,014)						-
Deferred Income Taxes	410/411	3,384,947	-	3,384,947						-
Other Operating Expenses -										
Salaries and Wages	MULTI	4,828,118	-	4,828,118		35.59	23.33	12.26	0.0336	162,225
Incentive Pay	MULTI	109,736	102,142	7,594	THF C-4	35.59	267.00	(231.41)	(0.6340)	(4,815)
Purchased Power	555	95,598,854	-	95,598,854		35.59	33.79	1.80	0.0049	468,434
Transmission Other	565	8,082,997	-	8,082,997		35.59	40.67	(5.08)	(0.0139)	(112,354)
Meter Reading	902	839,177	-	839,177		35.59	33.67	1.92	0.0053	4,448
Customer Records & Collection Expenses	903	1,389,213	-	1,389,213		35.59	34.94	0.65	0.0018	2,501
Office Supplies & Expenses	921	505,643	-	505,643		35.59	50.89	(15.30)	(0.0419)	(21,186)
Injuries and Damages	925	309,105	-	309,105		35.59	70.52	(34.93)	(0.0957)	(29,581)
Pension and Benefits	926	1,166,579	-	1,166,579		35.59	51.37	(15.78)	(0.0432)	(50,396)
Support Services (TEP)	MULTI	6,217,822	-	6,217,822		35.59	44.77	(9.18)	(0.0252)	(156,689)
Property Taxes	408	3,307,989	128,927	3,307,989	THF C-13	35.59	213.00	(177.41)	(0.4861)	(1,608,013)
Payroll Taxes	408	445,648	10,110	435,538	THF C-5	35.59	19.87	15.72	0.0431	18,772
Current Income Taxes	409	(1,263,680)	-	(1,263,680)		35.59	41.42	(5.83)	(0.0160)	20,219
Interest on Customer Deposits	431	14,499	-	14,499		35.59	182.50	(146.91)	(0.4025)	(5,836)
Other Operations and Maintenance	MULTI	10,986,786	75,798	10,910,988	THF C-9	35.59	41.21	(5.62)	(0.0154)	(168,029)
Total Operating Expenses		$ 150,922,718		$ 150,315,581						
Other Cash Working Capital Elements:										
Interest on Long-Term Debt	CALC	6,716,282	-	6,716,282		35.59	78.97	(43.38)	(0.1188)	(797,894)
Revenue Taxes and Assessments	CALC	12,430,745	-	12,430,745		35.59	49.43	(13.84)	(0.0379)	(471,125)
Total Cash Working Capital-calculated										$ (2,749,321)
Company Cash Working Capital										(2,810,346)
Change in working capital per staff										(61,025)

$40,792	EEI	THF--C7
$281,582	CALL CENTER	THF--C6
$132,159	INCENTIVE	THF--C3
$58,722	LEGAL EXPENSE	THF--C8
$66,667	RATE CASE EXP	THF--C10
$61,797	C.A.R.E.S.	THF--C11
$641,718		

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Post Test Year Non-Revenue Plant in Service
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Company post TY Non-Revenue Plant in Service	$7,263,614	Schedule B-3, Pg 1, line 1, Column C
2	Staff Adjustment to Post TY Non-Revenue Plant in Service	(7,263,614)	Staff Testimony
3	Adjustment	7,263,614	

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Adjusted Test Year Income Statement
Test Year Ended December 31, 2008

Line No.	Description	Company Unadjusted (a)		Company Pro Forma Adjustments (b)	Company	Staff Adjustments	Staff Adjusted	Line No.
	Operating Revenues							
1	Electric Retail Revenues	$181,638,915		($22,358,469)	$159,280,446	$61,797	$159,342,243	1
2	Sales for Resale	10,168,115		(10,168,115)	0	0	0	2
3	Other Operating Revenue	3,103,658		(1,458,039)	1,645,619	0	1,645,619	3
4	Total Operating Revenues	194,910,688		(33,984,623)	160,926,065	61,797	160,987,862	4
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	143,362,723		(32,059,158)	111,303,565	0	111,303,565	5
6	Other Operations and Maintenance Expense	21,569,849	(1)	(2,144,234)	19,425,615	(873,459)	18,552,156	6
7	Depreciation and Amortization	14,429,415		(194,193)	14,235,222	0	14,235,222	7
8	Taxes Other than Income Taxes	3,680,634		156,415	3,837,049	(442,526)	3,394,523	8
9	Income Taxes	2,081,685		39,582	2,121,267	481,859	2,603,126	9
10	Total Operating Expenses	185,124,306		(34,201,588)	150,922,718	(834,126)	150,088,592	10
11	*Operating Income*	9,786,382		$216,965	$10,003,347	$895,923	$10,899,270	11
	Other Income and Deductions							
12	Allowance for Equity Funds	322,168						
13	Other - Net	76,881						
14	Total Other Income and Dedu	399,049						
15	Income Before Interest Expense	10,185,431						
	Interest Expense							
16	Interest on Long-Term Debt	6,546,248						
17	Other Interest Expense	57,412	(1)					
18	Allowance for Borrowed Funds	(181,815)						
19	Total Interest Expense	6,421,845						
20	Net Income Available for Common Stock	$3,763,586						

(1) Includes reclasification of $160,200 for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense.

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Incentive Compensation Adj PEP	Incentive Compensation Adj SERP	Payroll Tax Expense, PEP	Call Center Expense Adj	Industry Association Dues	Legal Expense	Total Page Adjustments
	Operating Revenues							
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0
2	Sales for Resale	0	0	0	0	0	0	0
3	Other Operating Revenue	0	0	0	0	0	0	0
4	Total Operating Revenues	0	0	0	0	0	0	0
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	132,159	102,142	10,110	281,582	40,792	58,722	625,507
7	Depreciation and Amortization	0	0	0	0	0	0	0
8	Taxes Other than Income Taxes	0	0	0	0	0	0	0
9	Income Taxes	0	0	0	0	0	0	0
10	Total Operating Expenses	132,159	102,142	10,110	281,582	40,792	58,722	625,507
11	Operating Income	($132,159)	($102,142)	($10,110)	($281,582)	($40,792)	($58,722)	($625,507)

1
Docket No. E-04204A-09-0206
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Fuel Expense Adjustment	Rate Case Expense	C.A.R.E.S. Expense	B ad Debt Expense	Depreciation and Property Tax for Post TY Non-Rev Plant in Service	Income Tax	Total Page Adjustments	Total Adjustment
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$61,797	$0	$0	$0	$61,797	$61,797
2	Sales for Resale	0	0	0	0	0	0	0	0
3	Other Operating Revenue	0	0	0	0	0	0	0	0
4	Total Operating Revenues	0	0	61,797	0	0	0	61,797	61,797
	Operating Expenses								
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	75,798	66,667	0	105,487	0	0	247,952	873,459
7	Depreciation and Amortization	0	0	0	0	313,599	0	313,599	313,599
8	Taxes Other than Income Taxes	0	0	0	0	128,927	0	128,927	128,927
9	Income Taxes	0	0	0	0	0	(481,859)	(481,859)	(481,859)
10	Total Operating Expenses	75,798	66,667	0	105,487	442,526	(481,859)	208,619	834,126
11	Operating Income	($75,798)	($66,667)	$61,797	($105,487)	($442,526)	$481,859	($146,822)	($772,329)

Supporting Schedules
Schedules THF C-3 through THF C-13

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Incentive Compensation PEP
Test Year Ended December 31, 2008

Line No.	Description	Company Amount (A)	Disallowance Percentage (B)	Staff Adj Amount (C)
1	Incentive Compensation TY end Dec '08	$264,317	50%	$132,159

Source:

A: FERC form No. 1 p. 450.1
B: From Decision 70360
C: Column A x Column B

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Incentive Compensation Adj SERP
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	SERP Amount	$102,142	From FERC Form No. 1 p 450.1
2	SERP Adjustment (100%)	$102,142	Decision 70360

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Payroll Tax Expense, PEP Incentive
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	PEP Incentive Disallowance	$132,158	Schedule THF C-3
2	Payroll Tax Expense PEP	$10,110	7.65%
3	Adjustment	$10,110	Line 1 X Line 2

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Call Center Expense Adjustment
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Annual Allocation Last Case	$598,951	Docket No. E-04204A-06-0783 RUCO RLM-14 Line 23
2	Total Call Center Allocation Test Year	$880,533	TEP Invoices
4	Adjustment	$281,582	Line 2 - Line 3

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Industry Association Dues
Test Year Ended December 31, 2008

Line No.	Description	Amount	Referenc
1	Dues	$81,699	A
2	Percentage Disallowance	49.93%	B
3	Disallowance	$40,792	C
4	Adjustment	$40,792	

Source:

A: FERC Form 1 p. 335
B: Disallowance Percentage Decision 70360
C: Line 1 x Line 2

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Legal Expenses
Test Year Ended December 31, 2008

Schedule THF C-8
Page 1

Line No.	Year	Total Amount	Excluded	Allowable Amount	Staff Adj	Reference
1	2005	127,621.78	0.00	127,621.78	127,621.78	
2	2006	106,263.16	0.00	106,263.16	106,263.16	
3	2007	452,227.78	271,321.65	180,906.13	0.00	A
		686,112.72	271,321.65	414,791.07	233,884.94	
		Prior 3 year Avg.		138263.69	$87,552.00	B
	TY 2008	170,623.45	141,793.56	28,829.89	$28,830.00	
			Proforma	109,433.80	$58,722.00	C

A: Staff Removed as non-normal
B: 3 year Average Allowable Amount 2005, 2006, 2008 TY
C: Company 3 Year Average less Staff 3 Year Average

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Fuel Expense Adjustment
Test Year Ended December 31, 2008

Line No.	Description	A Gasoline	B Diesel	C Total Cost	Reference
1	Gallons	22,392	49,474		STF 1.59
2	Price/Gallon (TY)	$3.32	$3.82		STF 1.59
3	Calculations	$74,341	$188,991		STF 1.59
4	Company Totals			$263,332	A3 + B3
5	Adjusted Prices	$2.52	$2.65		AAA Year to Date Average
6	Adjusted Cost	$56,428	$131,106		Line 2 x Line 4
7	Total Fuel Cost			$187,534	A5 + B6
8	Staff Adjustment			$75,798	C4 - C7

UNS Electric, Inc.
Docket No E-04204A-09-0206
Rate Case Expense per ACC Decision No. 70360
Test Year Ended December 31, 2008

(A)	*nt Test Year Activity to be removed from Test year*	$58,333
(B)	Rate Case Expense allowed per ACC Decision No. 70360	$300,000
	Yearly Amortization (Starting June 2008)	$100,000
	Montly Amortization (Starting June 2008)	$8,333
	Amortization June 2008 - June 2010 (25 months)	$208,333
	Remaining Balance @ June 30, 2010	$91,667
	Amortization for Test Year Balance @ June 30, 2010 over 3 years	$30,556
(C)	Estimated Rate Case Expense for Current Case*	$166,667
	TOTAL Company Proforma Adjustment	$138,890
	Staff Adjustment Remove $200,000 from (C)	$200,000
	Reduce (C) by 1/3	$66,667
(D)	Decision No. 70360, pgs 23-24	

1) Assuming new rates will go into effect 14 months after the rate case is filed in May 2009 (in effect as of July 1, 2010)
*UNS Electric is requesting rate case of $500,000 aportized over three years

Line No.	Description	Amount	Reference
1	Company C.A.R.E.S. Adjustment	($61,797)	Company Workpapers
2	Remove Company Adjustment	$61,797	T. Fish Direct Testimony
3	Adjustment	$61,797	

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Bad Debt Expense
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Test Year Adjusted Revenue	$184,304,880	Schedule THF C-1
2	3 Year Average % Exp/Revenue	0.004718	Pro Forma Work Papers
3	Test Year Average Bad Debt	$869,550	Line 1 x Line 2
4	Test Year Actual Bad Debt	$1,200,504	Proforma Work Papers
5	Adjustment Required	$330,954	Line 4 - lind 3
6	Company Proforma Adjustment	$436,441	Company Schedule C-2
7	Staff Adjustement	$105,487	Line 6 - Line 5

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Depreciation and Property Tax for Post TY Plant in Service
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Depreciation & Property Tax .	$442,526	Company Schedule C2 P. 3 Line 11
2	Depreciation & Propery Tax /	$442,526	Remove Post TY PIS Amount
3	Adjustment Amount	$442,526	

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

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ATTACHMENT

SCHEDULES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

My direct testimony provides my estimate of the cost of capital for UNS Electric, Inc. ("UNS Electric"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	54.24%	7.05%	3.82%
Common Equity	45.76%	9.5 – 10.5%	4.35 – 4.80%
Total Capital	100.00%		8.17 – 8.63%
			8.40% Mid-point

The only difference between my 8.40 percent recommendation and the 9.04 percent cost of capital request of UNS Electric is the cost of common equity – I propose a cost of equity of 10.0 percent and UNS Electric requests a cost of equity of 11.4 percent.

My 10.0 percent cost of common equity is derived from my application of three cost of equity models:

Discounted Flow	9.4 – 10.1%
Capital Asset Pricing Model	7.6 – 8.3%
Comparable Earnings	9.5 – 10.5%

My 10.0 percent cost of equity recommendation is the same level of return that the Commission approved for UNS Electric in the Company's last rate proceeding.

In addition, my direct testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of UNS Electric. I recommend two alternative FVROR values for UNS Electric – a 5.65 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 5.99 percent value using a 1.50 percent inflation-adjusted risk-free return.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings, dating back to 1972. In connection with this, I have previously filed testimony and/or testified in about 450 utility proceedings before about 50 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the current filing of UNS Electric, Inc. ("UNS Electric" or "Company"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Electric. In addition, since UNS Electric is a subsidiary of UniSource Energy Corporation ("UniSource"), I have also evaluated UniSource in my analyses.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, made up of 14 Schedules, identified as Schedule 1 through Schedule 14. These Schedules were prepared either by me or under my direction. The information contained in these schedules is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendations for UNS Electric are:

	Percent	Cost	Return
Long-Term Debt	54.24%	7.05%	3.82%
Common Equity	45.76%	9.5-10.5%	4.35-4.80%
Total	100.00%		8.17-8.63%
			8.40%
			with 10.0% ROE

UNS Electric's application requests a return on common equity of 11.4 percent and overall rate of return of 9.04 percent. I propose a return on common equity of 10.0 percent and an overall rate of return of 8.40 percent.

Q. PLEASE SUMMARIZE YOUR COST ANALYSES AND RELATED CONCLUSIONS FOR UNS ELECTRIC.

A. This proceeding is concerned with UNS Electric's regulated electric utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. UNS Electric's proposed capital structure is comprised of

45.76 percent common equity and 54.24 percent long-term debt. This capital structure is the December 31, 2008 adjusted test period capital structure of the Company. I also use this same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of debt. UNS Electric's application uses a cost rate of 7.05 percent, which reflects the Company's cost at December 31, 2008. I have used the same rate for this item as is proposed by the Company.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Electric. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.4-10.1%
Capital Asset Pricing Model	7.6-8.3%
Comparable Earnings	9.5-10.5%

Based upon these findings, I conclude that the cost of common equity for UNS Electric is within a range of 9.5 percent to 10.5 percent. I recommend the mid-point of my cost of equity range (10.0 percent), which is the same cost of equity approved by the Commission in UNS Electric's last rate case. There is no indication that UNS Electric's level of risk has increased since the last proceeding. In addition, there are indications that capital costs have declined since the last case. Finally, the current economic recession should have the effect of lowering the cost of equity, because of a decline in profit levels and growth rates throughout the economy. In any event, the impact of depressed economic circumstances has negative effects on all of UNS Electric's customers (residential, commercial, and industrial) – there is no justification for increasing UNS Electric's profit level at the same time that virtually all of its customers are suffering from lower incomes/profits.

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 8.17 percent to 8.63 percent. My recommended 10.0 percent cost of equity results in an overall cost of capital of 8.40 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Public utility rates are normally established in a manner designed to allow for the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets used and useful (*i.e.*, rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return (including income taxes).

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an *ex post* (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an *ex ante* (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the main standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> "What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally". **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> "The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the

> enterprise, so as to **maintain its credit** and to **attract capital**." **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company, 294 P.2d 378 (1956) the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various

> permissible ways in which any rate base on which the return is computed might be arrived at."

My testimony does not advocate that the Commission ignore the Simms holding in this regard, or the fair value of UNS Electric's property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions can be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Electric Witness Pritz also cites the Hope and Bluefield cases as guidelines for evaluating the cost of capital for the Company.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Comparable Earnings ("CE") and Risk Premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I have utilized three methodologies to determine UNS Electric's cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as I indicate later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN DETERMINING THE COST OF CAPITAL FOR UNS ELECTRIC?

A. Yes. The costs of capital for both fixed-cost (debt and preferred stock) components and for common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the *Bluefield* decision, where the Court noted: "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over three full business cycles, plus the current cycle to date, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS CYCLES AND THE MOST RECENT CYCLE.

A. The three prior complete cycles and most recent cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-Aug. 2009 ?

Source: National Bureau of Economic, Research, "Business Cycle Expansions and Contractions."

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE RECENT TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON CAPITAL COSTS OVER THIS BROAD PERIOD?

A. Yes, I do. As I will describe below, until the end of 2007, the U.S. economy had enjoyed general prosperity and stability over the period since the early 1980s. This period had been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs.

Over the past two years, on the other hand, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crises in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of venerable institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national entities, such as Circuit City, and the declared bankruptcy of automotive manufacturers, such as Chrysler and General Motors.

This crisis has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." The U.S. and other governments have been and remain in the process of implementing unprecedented actions to attempt to correct or minimize its scope and effects.

There is a universal acceptance that the economy has been in a serious recession. The impacts of a severe recession on cost of capital is characterized by lower utility growth and declining capital costs due to a decline in corporate profits and expected earnings growth. Clearly, this is not an environment in which it is sensible or appropriate to increase the profitability of a regulated company such as UNS Electric.

It appears that the recession has reached its low point and that the economy may soon begin to expand again. However, the length and severity of the recession, as well as an anticipated relatively slow recovery, implies that the impacts of the recession will be felt for an extended period of time.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. My Schedule 2 shows several sets of relevant economic data for the time periods cited above: pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain financial market statistics.

Pages 1 and 2 show that the U.S. economy ended 2007 as the sixth year of an economic expansion but, as indicated previously, it was then entering a decline. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and the increase in the unemployment rate, which is currently approaching 10 percent on a national basis.

The rate of inflation is also shown on pages 1 and 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle, and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008 was the lowest level of the past thirty years. This is indicative of virtually no inflation, which should also be reflective of lower capital costs.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES OVER THIS TIME PERIOD?

A. Pages 3 and 4 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

During the past several years and up until the later half of 2008, long-term interest rates remained low by historic standards. Most recently, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on several occasions; currently it is 0.25 percent, an all-time low. The fourth quarter of 2008 and first quarter of 2009 experienced a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields and an increase in corporate bond yields, creating a "spread" between government and corporate bond yields unprecedented in recent financial history. This reflects the "flight to safety" I have mentioned.

On the other hand, I note that there is recent evidence that investors appear to have an appetite for accepting some risk again, as stock prices have improved and there has been a tightening in spreads between corporate debt vs. U.S. Treasury debt. Utility bond yields in August and September are, in fact, lower than those in mid-2008 prior to the financial crisis.

Q. WHAT DOES THIS EXHIBIT SHOW FOR THE TRENDS IN COMMON SHARE PRICES?

A. Pages 5 and 6 show several series of common stock prices and ratios. These ratios indicate that share prices were essentially stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycles witnessed a significant upward trend in stock prices. Since the beginning of the current financial crisis, on the other hand, stock prices declined precipitously and have been very volatile. Stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crises. Beginning in the second quarter of 2009, prices have recovered somewhat but still remain well below the levels prevailing prior to the current recession.

Q. WHAT CONCLUSIONS SHOULD THE COMMISSION DRAW FROM YOUR DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS DEPICTED IN YOUR DATA?

A. It is apparent that recent economic and/or financial circumstances have been radically different from any that have prevailed since at least the 1930s. The recent deterioration in stock prices and the decline in U.S. Treasury bond yields, and the increase in corporate bond yields reflected the "flight to safety," describes the reluctance of investors to purchase common stocks and corporate bonds while moving their money into the very safe government bonds. On the other side of this flight to safety is the negative perceptions of the recent decline, which has significantly reduced the value of most retirement accounts, investment portfolios and other assets; i.e., a decline in investor expectations of returns, including stock returns.

Q. GIVEN THE RECENT UNCERTAINTY IN THE CAPITAL MARKETS, WHY ISN'T IT REASONABLE TO CONCLUDE THAT THE COST OF CAPITAL FOR EQUITIES HAS INCREASED?

A. This "flight to safety" should not be interpreted to reflect an increase in the cost of capital. Rather, it more properly reflects an "availability of capital" since investors were recently unwilling to invest in any assets other than U.S. Treasury securities although this relationship has recently been much less pronounced. As I noted previously, the opportunity cost of capital, as measured by the recent and current returns of unregulated firms, has been the lowest in recent memory. Clearly, this cannot be claimed to reflect an increase in the cost of capital for a regulated firm such as UNS Electric.

V. UNS ELECTRIC'S OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE UNS ELECTRIC AND ITS OPERATIONS.

A. UNS Electric is a public utility that provides electric utility services to some 90,000 customers in Arizona. UNS Electric was formerly the Arizona electric utility operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. PLEASE DESCRIBE UNISOURCE ENERGY.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which is the parent company of both UNS Electric and UNS Gas. It previously owned Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary was Global Solar. UniSource Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF UNISOURCE ENERGY IN RECENT YEARS?

A. This is shown on Schedule 3. As this indicates, as of 2008, UNS Electric accounted for about 14 percent of the revenues of UniSource Energy and about 8 percent of operating income and total assets.

Q. WHAT ARE THE CURRENT BOND RATINGS OF UNISOURCE ENERGY, UNS ELECTRIC AND TEP?

A. The current ratings of UniSource Energy, UNS Electric and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
UNS Electric Credit Ratings			
Senior Unsecured Debt		Baa3	
UNS Gas		Baa3	
Senior Unsecured Debt			
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB+	Baa1	BBB-
Senior Unsecured Debt	BBB-	Baa3	BB+
Issuer Rating	BB+	Baa3	BB

Source: UniSource Energy Web Site.

UNS Electric now has its own security ratings by Moody's but not S&P and Fitch. The debt of UNS Electric is guaranteed by UES. As such, the debt of UNS Electric is related to the overall credit strength of UniSource Energy.

Q. DID THE ACQUISITION OF THE ASSETS CURRENTLY COMPRISING UNS ELECTRIC HAVE ANY IMPACT ON THE SECURITY RATINGS OF UNISOURCE ENERGY OR TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and **gas transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. WHAT HAVE BEEN THE RECENT DESCRIPTIONS OF UNS ELECTRIC BY RATING AGENCIES?

A. In July of 2008, Moody's assigned a rating of Baa3 to UNS Electric. In its report, Moody's stated:

Corporate Profile

UNS Electric, Inc. (UNSE: Baa3 guaranteed revolving credit facility, stable outlook) is an electric transmission and distribution utility serving approximately 90,000 retail customers in Mohave and Santa Cruz counties of Arizona. UNSE is a subsidiary of UniSource Energy Services ("UES') which is also the parent of UNS Gas, Inc. ("UNSG"), a gas utility serving approximately 146,000 customers in an area covering approximately 50% of the state of Arizona. UES is a wholly owned subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of certain subsidiaries), stable outlook). UNS' largest subsidiary is Tucson Electric Power (TEP: Baa3 senior unsecured, stable outlook), a vertically integrated electric utility serving approximately 400,000 retail customers in southeastern Arizona and also engaged in wholesale power marketing in the western U.S.

Recent Developments

On July 8, 2008, Moody's assigned a rating of Baa3 to UNSE and UNSG joint $60 million senior unsecured guaranteed credit facility. The facility is guaranteed by UNSE's and UNSG's intermediate parent company UES. The rating outlook is stable.

. . .

Rating Rationale

The **Baa3 rating for the shared guaranteed credit facility is driven by the relatively stable and predictable nature of UNSE's and UNSG's regulated cash flows, as well as their strong combined financial profile which provide the basis of the UES guarantee. For the past several years, cash flow credit metrics at both UNSE and USE have been at or above the ranges demonstrated by electric utilities rated within the Baa range**. [Emphasis added]

This quote by Moody's indicates that the ratings of UNS Electric are:

Tied to UNS Gas;

Based on consolidated credit profile of UES; and,

Lower than they would be if UNS Electric's own credit profile was used to establish its ratings.

Q. ARE YOU AWARE THAT ONE OF THE ISSUES IN THIS CASE IS THE POTENTIAL ACQUISITION OF THE BLACK MOUNTAIN GENERATION STATION BY UNS ELECTRIC FROM AN AFFILIATE COMPANY?

A. Yes I am. It is my understanding that UNS Electric is proposing to purchase this plant from an affiliated company – UniSource Energy Development ("UED") – and is asking for a commitment from the Commission that the plant will be included in rate base if transfer of ownership of the facility from UED to UNS Electric were to occur. It is also my understanding that UNS Electric is maintaining that it cannot afford to finance the purchase of this plant due to the relatively small size of the Company and the relatively large size of this generation facility. It is also my understanding that UNS Electric indicates that it would have a problem getting a lender to commit to providing debt capital to fund a portion of this potential purchase without assurance that the plant will be in rate base and thus provide a source of interest and principal repayment.

Q. WHAT IS YOUR UNDERSTANDING OF HOW THIS PLANT WAS FINANCED BY UED.

A. It is my understanding that UED financed this plant by use of credit facilities and internal cash generation of UniSource Energy and/or other affiliated companies. I am not aware of any specific debt or project financing associated with the Black Mountain facility.

Q. DO YOU HAVE ANY RESPONSE TO UNS ELECTRIC'S INDICATIONS THAT IT IS UNABLE TO FINANCE THE POTENTIAL PURCHASE OF BLACK MOUNTAIN WITHOUT SOME GUARANTEE OF COMMISSION INCLUSION OF THIS PLANT IN RATE BASE IN THIS PROCEEDING?

A. Yes, I do. I note, however, that I am not privy to the management decisions of the Company and do not have access to the same degree of the Company's financial alternatives as does the Company management. Nevertheless, I do have the following observations about the financing of the potential purchase of Black Mountain by UNS Electric. First, the facility is presently financed by some combination of internal funds of UniSource. It would appear that a potential interim source of financing the facility would be the transfer of the assets and liabilities within the UniSource framework to UNS Electric.

In addition, I note that UNS Electric has access to a revolving credit facility, as cited in witness Pritz's testimony, which it shares with UNS Gas. It is my understanding that UNS Electric may draw up to $35 million on this facility. This would also appear to be a source of interim financing for the potential purchase of Black Mountain.

Q. HAS THIS COMMISSION AUTHORIZED UNS ELECTRIC TO ISSUE ANY SECURITIES FOR THE PURPOSE OF FINANCING THE PURCHASE OF BLACK MOUNTIAN?

A. Yes, it has. In Docket No. E-04204A-06-0783 (Decision No. 70360) the Commission authorized UNS Electric to issue $40 million of equity and $40 million of debt for the purpose of financing the purchase of Black Mountain.

Q. HAS THE COMPANY EXERCISED ANY OF THE OPTIONS AUTHORIZED BY THE COMMISSION IN THAT PROCEEDING?

A. No, it has not issued the securities authorized in that proceeding.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (*i.e.*, the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF UNS ELECTRIC?

A. I have first examined the historic (2004-2008) capital structure ratios of UNS Electric. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for UNS Electric:

	Including S-T Debt	Excluding S-T Debt
2004	40.3%	40.5%
2005	45.2%	45.4%
2006	45.0%	45.1%
2007	48.0%	48.1%
2008	43.6%	43.7%
June 30, 2009	46.2%	46.2%

Page 2 of Schedule 4 shows the historic capital structure ratios of UniSource on a consolidated basis. This indicates the following common equity ratios.

	Including S-T Debt	Excluding S-T Debt
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%
2007	40.7%	41.0%
2008	33.9%	34.1%

These common equity ratios are somewhat lower than those of UNS Electric.

Q. HOW DO THESE CAPITAL STRUCTURES COMPARE TO THOSE OF INVESTOR-OWNED ELECTRIC UTILITIES?

A. Schedule 5 shows the common equity ratios (excluding short-term debt in capitalization) for the two groups of proxy utilities utilized in my cost of equity analyses. These are:

Year	Proxy Group	Pritz Group
2004	41.5%	52.1%
2005	43.6%	51.8%
2006	45.1%	52.5%
2007	48.0%	51.5%
2008	46.8%	50.8%

These common equity ratios for the proxy group are lower than those of UNS Electric while those of the Pritz Group are higher.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS UNS ELECTRIC REQUESTED IN THIS PROCEEDING?

A. The Company requests use of the following capital structure:

Long-Term Debt	54.24%
Common Equity	45.76%

According to UNS Electric's filing, this is the "adjusted" test year capital structure of the Company at December 31, 2008.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I use the capital structure ratios as proposed by UNS Electric.

Q. WHAT IS THE COST RATE OF DEBT IN THE COMPANY'S APPLICATION?

A. The Company's filing cites a cost of long-term debt of 7.05 percent. This is represented to be the Company's actual cost at December 31, 2008. I also use this cost of long-term debt in my cost of capital analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COSTS OF DEBT?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR UNS ELECTRIC?

A. UNS Electric is not a publicly-traded company. UniSource, UNS Electric's parent company, is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to UniSource. However, it is generally desirable to analyze groups of comparison, or "proxy," companies as a substitute for UNS Electric to determine its cost of common equity.

I have examined two such groups for comparison to UNS Electric and UniSource. I have first selected a group of electric utilities similar to UNS Electric and UniSource using the criteria listed on Schedule 6.

Second, I have conducted studies of the cost of equity for the proxy group of electric utilities selected by UNS Electric's witness Martha B. Pritz.

VIII. DCF ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DCF MODEL?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where:

K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; *i.e.*, current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (July-September, 2009). The D_0 is the current annualized dividend rate for each proxy company.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2004-2008 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2009, 2010, and 2012-2014 projections of earnings retention growth (per Value Line);

4. 2006-2008 to 2012-2014 projections of EPS, DPS, and BVPS (per Value Line); and

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, and low/high values. These results can be summarized as follows:

			Composite			
			Mean		Median	
	Mean	Median	Low	High	Low	High
Proxy Group	10.1%	9.6%	8.6%	12.3%	8.9%	11.8%
Pritz Group	9.5%	9.4%	8.2%	11.7%	7.4%	11.6%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 9.4 percent to 10.1 percent. The range of DCF rates (i.e., using the lowest and highest growth rates only) is 7.6 percent to 12.3 percent.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. This analysis reflects a DCF range of about 9.4 percent to about 10.1 percent for the proxy group. This is indicated by the average/mean values for the proxy groups examined in the previous analysis. I give less weight to the extreme lower and upper ends of the groups, which are impacted by outlier results. I believe that 9.4 percent to 10.1 percent reflects the proper DCF cost for UNS Electric. .

IX. CAPM ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPM.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where:

K = cost of equity

Rf = risk-free rate

Rm = return on market

β = beta

Rm-Rf = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. PLEASE EXPLAIN THE RISK-FREE RATE AS USED IN YOUR CAPM AND INDICATE WHAT RATE YOU EMPLOYED.

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (July-September, 2009) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 4.28 percent.

Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT IN YOUR CAPM ANALYSIS?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the

S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2007 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (*i.e.*, risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.45 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by MorningStar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2008 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.7%	6.1%	5.6%
Geometric	9.6%	5.7%	3.9%

I conclude from this that the expected risk premium is about 5.32 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using this risk premium. The results are:

	Mean	Median
Proxy Group	8.3%	8.3%
Pritz Group	7.6%	8.0%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY?

A. The CAPM results collectively indicate a cost of 7.6 percent to 8.3 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for UNS Electric is 7.6 percent to 8.3 percent.

X. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF UNS ELECTRIC'S COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (*i.e.,* 100%) reflect a situation where a company is able to attract new equity capital without dilution (*i.e*., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2009 (*i.e.,* the last eighteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2009 (the current business cycle) and 1992-2001 (the prior business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Pritz Group
Historic ROE		
Mean	8.2-10.0%	9.4-10.0%
Median	8.2-11.1%	9.3-11.1%
Historic M/B		
Mean	129-152%	154-157%
Median	120-144%	142-155%
Prospective ROE		
Mean	9.0-9.1%	9.6-10.2%
Median	8.5%	9.5-10.0%

These results indicate that historic returns of 8.2 percent to 11.1 percent have been adequate to produce market-to-book ratios of 120 percent to 157 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2010 and 2012-2014 are within a range of 8.5 percent to 10.2 percent for the utility groups. These relate to 2008 market-to-book ratios of 115 percent or higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past sixteen years. As this Schedule indicates, over the two periods, this group's average earned returns ranged from 13.9 percent to 14.7 percent with market-to-book ratios ranging between 284 percent and 341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR UNS ELECTRIC?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.5 percent. Recent returns of 8.2 percent to 11.1 percent have resulted in market-to-book ratios of 120 and greater. Prospective returns of 8.5 percent to 10.2 percent result in anticipated market-to-book ratios of over 115 percent, again with the higher returns being associated with much higher market-to-book ratios. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9.5 percent to 10.5 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematical formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100%, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for UNS Electric. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following:

Discounted Cash Flow	9.4-10.1%
Capital Asset Pricing Model	7.6-8.3%
Comparable Earnings	9.5-10.5%

Q. WHAT IS YOUR COST OF EQUITY RECOMMENDATION FOR UNS ELECTRIC?

A. I recommend a cost of equity of 9.5 percent to 10.5 percent for UNS Electric. This range contains the results of two of my three cost of equity model results (i.e., DCF 9.4-10.1% and CA 9.5-10.5%). Within this range, I recommend a 10.0 percent level, the same return on equity approved for UNS Electric in the Company's last rate proceeding.

Q. IT APPEARS THAT YOUR CAPM RESULTS ARE SOMEWHAT LOWER THAN YOUR DCF RESULTS. DOES THIS INDICATE THAT THE CAPM RESULTS SHOULD NOT BE CONSIDERED AT THIS TIME?

A. No, this is not the case. It is apparent that the current CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for the lower CAPM results are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and the lower risk premium that reflects the decline in stock prices in 2008. However, these currently lower CAPM results are only one-half of the impact of recent economic conditions. The other impact is on the DCF results, which are somewhat higher currently due to the higher yields attributable to the decline in stock prices. It would not be proper to disregard the lower CAPM results while not discounting the higher DCF results.

Q. PLEASE EXPLAIN HOW THE RECENT AND CURRENT ECONOMIC AND FINANCIAL CRISIS IMPACTS THE COST OF EQUITY FOR UNS ELECTRIC.

A. It is well chronicled that, over the past two years, the United States and global financial markets have been in turmoil. The impacts of this have been far-reaching and extreme, with global credit markets virtually coming to a standstill in late 2008 and early 2009. This crisis and its impact, however, do not imply that the cost of equity for electric utilities such as UNS Electric have increased. I say this for the following reasons.

First, it must be emphasized that depressed economic conditions and the financial crisis affect virtually all sectors of the economy – households, small businesses, larger commercial and industrials – and, in most cases, the impact is greater than is the case for UNS Electric. UNS Electric is a regulated utility that sells a product that has no real substitutes and is a product that consumers can do little to control the amount they use. As such, UNS Electric and utilities are partially, if not largely, insulated from the impacts of depressed economic conditions.

Second, a major impact of a recession is to depress the profits of most enterprises. As a result, it is to be expected that capital costs decrease in tandem with a significant recession. There is no justification for increasing the profit level of a regulated utility such as UNS Electric at the same time that other enterprises are experiencing lower profits.

Third, even if UNS Electric were to incur higher costs of debt and/or other capital costs, these costs can be passed along to ratepayers at the next rate proceeding. Unregulated firms cannot do this.

Fourth, there is no indication that UNS Electric's risks have increased since its last rate proceeding. Absent a demonstration that UNS Electric's risks have increased, there is no justification for increasing its cost of equity.

Fifth, the United States and global governments have, and are taking, extraordinary measures to avoid a further worsening of the current market turmoil. Most of these measures are designed to put liquidity into the credit markets and make credit more accessible again and, in the process, restore more confidence to the financial markets. All of these measures are clearly designed to lower the cost of capital. In this environment, it would be counter-productive to make any claim that UNS Electric should have a higher return at this time due to the above-cited market turmoil.

XII. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR UNS ELECTRIC?

A. Schedule 1 reflects the total cost of capital for the Company using UNS Electric's proposed capital structure and cost of debt along with the range of common equity costs that my analyses support. The resulting total cost of capital is a range of 8.17 percent to 8.63 percent. I recommend that an 8.40 percent total cost of capital be established for UNS Electric.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Electric earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level above the benchmark range for a BBB rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a BBB rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY AND COST OF CAPITAL RECOMMENDATION OF UNS ELECTRIC WITNESS MARTHA B. PRITZ?

A. Yes, I have. Ms. Pritz is recommending the following cost of capital for UNS Electric.

Capital Item	Percent	Cost	Weighted Cost
Long-term Debt	54.24%	7.05%	3.82%
Common Equity	45.76%	11.40%	5.22%
Total	100.0%		9.04%

Ms. Pritz's 11.4 percent cost of common equity recommendation is derived as follows:

	Conclusion
DCF	12.1%
CAPM	10.1%
Risk Premium	12.0%

Q. DO YOU HAVE ANY COMMENTS CONCERNING MS. PRITZ'S DCF ANALYSIS AND RECOMMENDATIONS?

A. I note that Ms. Pritz's 12.1 percent DCF conclusion is based upon her application of a DCF model to a group of 10 electric utilities.

Q. WHAT IS YOUR UNDERSTANDING OF MS. PRITZ'S DCF METHODOLOGIES AND CONCLUSIONS?

A. Ms. Pritz applies a version of the non-constant growth DCF model. She combines each company's yield with the average of four "short-term" growth rates – three of which are projections of earnings per share ("EPS") growth. It is apparent, however, that Ms. Pritz's short-term DCF growth is deficient because it primarily focuses on only one source of growth - EPS projections. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth.

There are several reasons why it is not proper to rely exclusively on analysts' forecasts in a DCF context.

First, it is not realistic to believe that investors rely primarily on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks, and EPS forecasts are only one of many such statistics.

Second, Value Line, one of the sources of EPS projections, publishes a large number of individual company data and ratios. Presumably these are published for the consideration of subscribers/investors. It is also apparent that Value Line publishes both historic and forecast data – yet Ms. Pritz focuses on one factor and only the forecast version of this factor.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data to the exclusion of historic (actual) data.

Fourth, there have been a number of academic studies that indicate that analysts' forecasts have been overly-optimistic in the past. See, for example a 1998 article (in the Financial Analysts Journal, Vol. 54, No. 6, Nov./Dec. 1998, 35-42) titled "Why So Much Error In Analysts' Earnings Forecasts?," by Vijay Kumer Chopra. In this article, the author concluded "Analysts' forecasts of EPS and growth in EPS tend to be overly optimistic." He concluded that analysts' forecasts of EPS over the past 13 years have been more than twice the actual growth rate. Investors are aware of the propensity of analysts to over-estimate EPS forecasts. In addition, the presumption that investors rely only on a single projection implies that investors are unsophisticated and unable to make their own decisions. This also is not rational.

Fifth, the experience over the past two years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Hardly any security analysts predicted the decline in profits that occurred in 2008 and 2009 to-date.

Sixth, the well-publicized financial debacles of Enron and WorldCom demonstrate dramatically how analysts are often either unwilling or incapable of discerning potentially disastrous impacts of a company's projected EPS, and how even current earnings can be distorted by the complex financial machinations of large, aggressive corporations.

Finally, during 2003, ten of the nation's largest securities firms agreed to pay a record $1.4 billion in penalties to settle U.S. government charges involving investor abuses, many of which resulted from analysts' forecasts and recommendations that the government charged were biased and subject to conflicts of interests. This settlement largely grew out of a New York State investigation and reflects the national, and even international, scope of the negative perceptions of analysts' forecasts and recommendations. These, and other, similar investigations and complaints have underscored a growing awareness that analysts' estimates cannot be considered an unbiased source of growth expectations by investors, and this understanding has important implications for a DCF analysis that exclusively incorporates any such estimates.

In summary, investors are now very much aware of recent scandals involving security analysts, including the Enron and WorldCom debacles, conflicts of interest that have resulted in settlements, fines, and public admonishments, as well as other negative connotations related to the reliability of analysts' forecasts. These problems clearly call into question the reliance of analysts' forecasts as the only source of growth in a DCF context. The landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time.

Q. PLEASE NOW TURN TO MS. PRITZ'S LONG-TERM DCF GROWTH RATE.

A. The second, or "long-term" stage of her second DCF model relies exclusively on the 6.5 percent GDP growth as the DCF growth rate.

Q. WHAT IS THE SOURCE OF THIS 6.50 PERCENT GDP FIGURE?

A. According to Ms. Pritz, this 6.5 percent Gross Domestic Product ("GDP") growth is the average of real GDP Growth since 1929 plus "implied inflation."

Q. IS THERE ANYTHING INCONSISTENT WITH MS. PRITZ'S USE OF HISTORIC GDP GROWTH IN HER DCF ANALYSES?

A. Yes, there is. All of Ms. Pritz's other growth rates in her short-term DCF analyses (i.e., DPS and EPS growth) reflect projections of future growth. On the other hand, Ms. Pritz only uses historic rates in her GDP growth input. Apparently, she believes it is not proper to use historic growth rates of financial indicators (i.e., EPS growth), but it is proper to use only historic growth rates in her GDP input.

Q. ARE YOU AWARE OF ANY PROJECTIONS OF GDP GROWTH?

A. Yes, I am. There are at least two sources of projections of GDP growth. These are:

- Social Security Administration ("SSA"), and
- Energy Information Administration ("EIA"),

The two organizations cited above are U.S. government-sponsored organizations.

Q. WHAT ARE THE PROJECTIONS OF GDP GROWTH BY THESE TWO ORGANIZATIONS?

A. As of the most recent period available at the time Ms. Pritz was preparing her testimony, the projections of GDP growth by these two organizations were:

SSA – 2008-2085 – 4.4 percent (see Schedule 14)
EIA – 2007-2030 – 4.8 percent (see Schedule 14)

Each of these projections is at about 200 basis points below the 6.50 percent GDP figure used by Ms. Pritz.

Q. WOULD IT BE MORE APPROPRIATE TO USE HISTORIC OR PROJECTED GROWTH RATES OF GDP IN A DCF ANALYSIS SUCH AS THAT BEING USED BY MS. PRITZ?

A. It would be appropriate to use projections of GDP growth, since Ms. Pritz is using projections of the other growth rate indicators.

Q. IS IT REASONABLE TO BELIEVE THAT INVESTORS WOULD EXPECT GDP GROWTH TO BE 6.5 PERCENT, IN SPITE OF MUCH LOWER PROJECTIONS BY THE U.S. GOVERNMENT FORECASTING ORGANIZATIONS?

A. No, it is not.

Q. ARE YOU AWARE OF ANY UTILITY REGULATORY AGENCIES THAT UTILIZE GDP GROWTH AS A COMPONENT IN A DCF ANALYSIS?

A. The only regulatory agency of which I am aware that directly and formally uses GDP growth in a DCF context is the Federal Energy Regulatory Commission ("FERC"). The FERC regularly uses a two-stage DCF model in establishing the cost of equity for interstate natural gas pipelines. The first stage of the FERC two-stage DCF model is 5-year EPS forecasts, while the second stage is GDP projections for 6-25+ years into the future.

Q. HOW MUCH WEIGHT DOES FERC GIVE TO THE GDP GROWTH RATE IN ITS TWO-STAGE DCF MODEL?

A. 33 percent.

Q. ARE YOU AWARE OF ANY REGULATORY AGENCIES THAT USE HISTORIC GDP GROWTH IN A DCF CONTEXT?

A. No.

Q. WHAT ARE YOUR COMMENTS CONCERNING MS. PRITZ'S CAPM ANALYSIS AND CONCLUSIONS?

A. Ms. Pritz's CAPM analysis takes the following form:

Risk-free rate	=	3.83%	=	February 2009 20-yr. T bonds Yield
Risk Premium	=	6.5%	=	MorningStar risk premium
Beta			= [1] =	Value Line
Risk Premium Adj.	=	2.29%		

[1] Beta for each company.

My first disagreement is with Ms. Pritz's risk premium input. My disagreements with Ms. Pritz's risk premium is her exclusive reliance on the 1926-2008 arithmetic average differences between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done. Ms. Pritz's 6.5 percent risk premium used only arithmetic returns, and ignores geometric (compound) returns in deriving the risk premium component of the CAPM. This is not proper. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, which they use to make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Ms. Pritz's position that only arithmetic returns are considered by investors and, thus, only arithmetic returns are appropriate in a CAPM context.

I also disagree with Ms. Pritz's 6.5 percent risk premium since it improperly used "income returns" from the MorningStar study rather than "total returns." What Ms. Pritz did was compare the differential between total returns for common stocks (i.e., dividends and capital gains) and only the income returns for Treasury bonds. As such, she has ignored the capital gains component of the Treasury bonds return. As I indicated in my earlier testimony, the differential between total returns of common stocks and Treasury bonds is 5.6 percent on an arithmetic basis. In addition, Ms. Pritz's use of the MorningStar study only used half of the reported data (arithmetic means) and ignored the other half of the reported data (geometric means).

I also disagree with Ms. Pritz's 2.29 percent "risk premium adjustment." This adjustment, as described on page 14 of her testimony, reflects the "observed increase in long-term credit spreads" between August 2008 and January 2009. Her rational is based on the following relationships:

Time	Baa Yields	20-Year Treasury Yield	Difference
August, 2008	6.98%	4.50%	2.48%
January, 2009	7.90%	3.13%	4.77%
Change			2.29%

I have previously stated that the "flight to safety" during the timeframe of her January 2009 focal point should not be used as a standard for cost of capital determination. In addition, it is clear that the circumstance she cited no longer is in effect. In September of 2009, the respective yields are:

Baa Utility	6.12%
30-Year Treasury	4.19%
Difference	1.93%

This "spread" is less than existed in August of 2008. As a result, even if Ms. Pritz's logic (which I disagree with) was correct there is no justified "risk premium adjustment" at this time.

Q. WHAT ARE YOUR COMMENTS ABOUT MS. PRITZ'S BOND YIELD PLUS PREMIUM METHOD AND RESULTS?

A. Ms. Pritz's equity risk premium method looks at the relationship between state regulatory commission return on equity awards and corresponding public utility bond yields over the period 2006 – January 2009. On page 16 and MBP-12, she concludes that 4.07 percent reflects the appropriate spread between the cost of equity and utility bond yields, reflecting the yield of Baa utility bonds.

Combining this 4.07 percent equity risk premium with Ms. Pritz's estimate of 7.90 percent for public utility bonds in January of 2009 results in a cost of equity of about 11.97 percent. However, current yields on Baa rated utility bonds are much less at about 6.4 percent and are currently about 6.1 percent. Combining this with the 4.07 percent risk premium would result in a 10.2 percent cost of equity.

XIV. FAIR VALUE RATE BASE COST OF CAPITAL

Q. WHAT IS YOUR UNDERSTANDING OF UNS ELECTRIC'S POSITION ON THE ISSUE OF FAIR VALUE RATE BASE ("FVRB") AND RELATED COST OF CAPITAL IMPLICATIONS?

A. It is my understanding that UNS Electric is requesting that a 6.88 percent cost of capital be applied to the level of its FVRB if the Black Mountain Generating Station ("BMGS") is not purchased and placed in rate base, and is 7.29 percent if BMGS is in rate base (testimony of UNS Electric witness Kentton Grant).

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S PROCEDURE FOR UTILIZING THE FAIR VALUE OF RATE BASE IN SETTING UTILITY RATES?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. ARE YOU AWARE THAT THE COMMISSION HAS RECENTLY CONDUCTED A "REMAND" HEARING ON THE ISSUE OF REGULATORY TREATMENT OF FVRB FOR CHAPARRAL CITY WATER COMPANY?

A. Yes, I am. In January of 2008, the Commission conducted a public hearing in response to a remand by the Arizona Appeals Court (Appeals No. CA-CC 05-002) decision[2] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate cost of capital to be applied to an Arizona utility's fair value rate base. The Commission's Decision No. 70441 in this proceeding established a FVROR by subtracting the inflation rate from the cost of equity.

Q. WHAT IS YOUR UNDERSTANDING OF THE USE OF FVRB IN ARIZONA?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the

[2] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. DO YOU HAVE ANY OBSERVATIONS BASED UPON YOUR OWN EXPERIENCE IN COST OF CAPITAL DETERMINATION, AS TO WHETHER A COST OF CAPITAL DEVELOPED FOR APPLICATION TO AN ORIGINAL COST RATE BASE IS CONSISTENT WITH A FVRB?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary WCOC analysis and FVRB.

Q. WHY IS IT IMPORTANT THAT THERE BE A LINK BETWEEN THE CONCEPTS OF RATE BASE AND COST OF CAPITAL?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. BASED ON YOUR EXPERIENCE AS A COST OF CAPITAL WITNESS OVER THE PAST 35 YEARS, DO YOU HAVE A SUGGESTION AS TO HOW TO ACCOUNT FOR THE USE OF A FVRB IN SETTING RATES FOR UNS ELECTRIC?

A. Yes, I do. Since the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. HAVE YOU MADE SUCH A PROPOSAL IN THIS PROCEEDING?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to UNS Electric's FVRB.

Item	Amount (000)	Percent	Cost	Fair Value Return
Long-term Debt	$99,300	36.45%	7.05%	2.57%
Common Equity	83,800	30.76%	10.00%	3.08%
FVRB Increment[3]	89,333	32.79%	0.00%	0.00%
Total FVRB Capital	$272,433	100.00%		5.65%

Applying this 5.65 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE METHOD WITH WHICH TO APPLY A FVROR TO A FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. WHY IS IT NECESSARY TO ADD A RETURN ON ONLY THE PORTION OF FVRB THAT EXCEEDS THE OCRB?

A. The weighted cost of capital ("WCOC") authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need

[3] FVRB ($257,827,400) minus OCRB ($168,494,273), per the Testimony of Utilities Division Staff Witness Fish.

to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. WHAT IS THE PROPER COST RATE TO APPLY TO THE FAIR VALUE INCREMENT?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, I recognize that the Commission might choose to evaluate this issue from both a financial and a public policy perspective. I am aware that UNS Electric may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. WHAT IS THE RISK-FREE RETURN?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.10 percent (short-term) to 4.5 percent (long-term) in nominal terms. I also note that 2010-2011 forecasts of U.S. Treasury securities are about 1.0 percent to 5.0 percent. As a result, I use 5.0 percent as the nominal risk-free rate.

Q. WHAT IS THE "REAL" RISK-FREE RATE?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2008, the rate of inflation, as measured by the Consumer Price Index ("CPI'), was 0.1 percent. Forecasts of the CPI for 2009-2010 are about 1.3 percent to 2.1 percent. As a result, I propose to use a 2.0 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	5.0%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	3.0%

Q. PLEASE EXPLAIN WHY UNS ELECTRIC'S FVROR SHOULD CONSIDER THE REAL RISK-FREE RATE, AS OPPOSED TO THE NOMINAL RISK-FREE RATE.

A. The investors of UNS Electric are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. WHAT RETURN ON THE FAIR VALUE INCREMENT DO YOU RECOMMEND IN YOUR ALTERNATIVE FVROR PROPOSAL?

A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a maximum value of 3.0 percent, as developed above. However, I wish to emphasize that this 3.0 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 3.0 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.50 percent.

Q. WHAT IS THE RESULTING IMPACT OF YOUR ALTERNATIVE PROPOSAL IN THIS PROCEEDING?

A. I am proposing the following modified FVROR for UNS Electric:

Capital Item	Percent	Cost	Return
Long-term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
FVRB Increment	32.79%	1.50%	0.34%
Total	100.00%		5.99%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of UNS Electric, and provides for an overall fair value rate of return of 5.99 percent on the FVRB.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATION

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of

National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

<u>Utility Economics</u> -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

UNS ELECTRIC INC
TOTAL COST OF CAPITAL

Item	Percent	Cost			Weighted Cost		
Long-Term Debt	54.24%		7.05%			3.82%	
Common Equity	45.76%	9.50%	-	10.50%	4.35%		4.80%
Total	100.00%				8.17%		8.63%
						8.40%	**With 10.0% ROE**

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.8%	4.3%	4.2%	2.7%	2.9%
2000	4.1%	4.2%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.8%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.3%	5.1%	3.4%	5.4%
2006	2.7%	2.3%	4.6%	2.5%	1.1%
2007	2.1%	1.5%	4.6%	4.1%	6.2%
2008	0.4%	-2.2%	5.8%	0.1%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	1.2%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	3.6%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.1%	1.7%	4.8%	5.6%	12.8%
2008					
1st Qtr.	-0.7%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	1.5%	-0.4%	5.4%	7.6%	14.0%
3rd Qtr.	-2.7%	-3.2%	6.1%	2.8%	-0.4%
4th Qtr.	-5.4%	-6.7%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.4%	-11.6%	8.1%	2.4%	-1.2%
2nd Qtr.	-0.7%	-13.0%	9.3%	3.2%	8.8%
3rd Qtr.			9.6%		

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003						
Jan	4.25%	1.17%	4.05%	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%	6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%	6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%	6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%	6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%	6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%	6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%	6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%	6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%	6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%	6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%	6.18%	6.27%	6.61%
2004						
Jan	4.00%	0.89%	4.15%	6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%	6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%	5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%	6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%	6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%	6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%	6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%	5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%	5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%	5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%	5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%	5.78%	5.92%	6.10%
2005						
Jan	5.25%	2.32%	4.22%	5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%	5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%	5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%	5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%	5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%	5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%	5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%	5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%	5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%	5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%	5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%	5.55%	5.80%	6.14%
2006						
Jan	7.50%	4.20%	4.42%	5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%	5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%	5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%	6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%	6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%	6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%	6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%	5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%	5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%	5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%	5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%	5.62%	5.81%	6.05%
2007						
Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
2008						
Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%	5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
2009						
Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%	5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%	5.15%	5.53%	6.12%

Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.55%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.70	996.70	9,229.93	2.16%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2006 - 2008
($millions)

Segment	Operating Revenues	Operating Income	Total Assets
		2006	
Tucson Electric Power Co	$989	$216	$2,623
	75.6%	90.0%	82.3%
UNS Gas	$162	$13	$253
	12.4%	5.4%	7.9%
UNS Electric	$160	$13	$195
	12.2%	5.4%	6.1%
All Other	$14		$1,038
	1.1%	0.0%	32.6%
Unisource Energy	$1,308	$240	$3,187
		2007	
Tucson Electric Power Co	$1,071	$189	$2,573
	77.6%	88.7%	80.8%
UNS Gas	$151	$12	$276
	10.9%	5.6%	8.7%
UNS Electric	$169	$12	$231
	12.2%	5.6%	7.3%
All Other	$12		$1,077
	0.9%	0.0%	33.8%
Unisource Energy	$1,381	$213	$3,186
		2008	
Tucson Electric Power Co	$1,079	$107	$2,842
	77.2%	73.8%	81.0%
UNS Gas	$174	$20	$294
	12.4%	13.8%	8.4%
UNS Electric	$195	$12	$285
	13.9%	8.3%	8.1%
All Other	$23		$1,061
	1.6%	0.0%	30.2%
Unisource Energy	$1,398	$145	$3,510

UNS Gas, TEP and UNS Electric figures do not total to Unisource Energy cosolidated figures due to other activities of Unisource Energy.

Source: Unisource Energy Corporation 2008 Form 10-K.

UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2003 - 2009
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$40,900	$60,000	$600
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	$49,900	$60,000	$500
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	$64,900	$79,000	$400
	45.0%	54.7%	0.3%
	45.1%	54.9%	
2007	$79,800	$86,000	$400
	48.0%	51.7%	0.2%
	48.1%	51.9%	
2008	$83,800	$108,000	$200
	43.6%	56.3%	0.1%
	43.7%	56.3%	
June 30, 2009	$86,000	$100,000	$200
	46.2%	53.7%	0.1%
	46.2%	53.8%	

Source: Response to STF 7.2

UNISOURCE ENERGY CORP
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$581	$1,258	$0
	31.6%	68.4%	0.0%
	31.6%	68.4%	
2005	$617	$1,212	$5
	33.6%	66.1%	0.3%
	33.7%	66.3%	
2006	$654	$1,171	$50
	34.9%	62.5%	2.7%
	35.8%	64.2%	
2007	$690	$994	$10
	40.7%	58.7%	0.6%
	41.0%	59.0%	
2008	$679	$1,314	$10
	33.9%	65.6%	0.5%
	34.1%	65.9%	

Source: Unisource Energy Corporation 2008 Form 10-K.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource	$679.3	$1,313.6	$10.0
Energy	33.9%	65.6%	0.5%
consolidated	34.1%	65.9%	
UNS Gas	$96.7	$100.0	$0
	49.2%	50.8%	0.0%
	49.2%	50.8%	
UNS Electric	$83.8	$108.0	$200
	21.4%	27.6%	51.0%
	43.7%	56.3%	
TEP	$583.6	$903.6	$10.0
	39.0%	60.4%	0.7%
	39.2%	60.8%	

Source for Unisource Energy Consolidated and TEP is 2008 10-K
Source for UNS Gas and UNS Electric is Response to STF 7.2.

Exhibit___(DCP-1)
Schedule 5

PROXY GROUPS
COMMON EQUITY RATIOS

COMPANY	2004	2005	2006	2007	2008	Average	2012-2014
Parcell Proxy Group							
Avista Corp.	41.9%	40.6%	46.3%	59.0%	51.9%	47.9%	50.0%
Hawaiian Electric Industries, Inc	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
Pinnacle West Capital Corp.	53.3%	56.8%	51.6%	53.0%	53.2%	53.6%	50.0%
Pepco Holdings, Inc.	39.6%	42.3%	45.1%	45.9%	43.8%	43.3%	48.5%
TECO Energy, Inc.	24.9%	30.0%	35.0%	39.0%	38.5%	33.5%	41.5%
Westar Energy, Inc.	45.5%	47.2%	49.3%	48.9%	49.7%	48.1%	52.5%
Average	41.5%	43.6%	45.1%	48.0%	46.8%	45.0%	48.8%
Pritz Comparable Company Group							
ALLETE, Inc.	61.8%	60.9%	64.9%	64.4%	58.4%	62.1%	51.5%
CH Energy Group, Inc.	59.1%	58.0%	58.8%	55.2%	54.6%	57.1%	48.5%
Empire District Electric Co.	48.7%	49.0%	50.3%	49.9%	46.4%	48.9%	49.0%
Hawaiian Electric Industries	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
MGE Energy, Inc.	62.6%	60.7%	61.3%	64.8%	63.7%	62.6%	65.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
NorthWestern Corp.							
NSTAR	40.2%	38.6%	39.7%	40.1%	42.8%	40.3%	54.0%
Portland General Electric	58.9%	57.7%	56.6%	50.1%	53.8%	55.4%	50.5%
UIL Holdings	52.8%	52.8%	53.0%	49.2%	46.4%	50.8%	48.0%
Average	52.1%	51.8%	52.5%	51.5%	50.8%	51.8%	51.7%

Source: Value Line.

PROXY COMPANIES

Company	Market Capitalization ($ millions)	Percent Reg Elec or Gas Revenues	Common Equity Ratio	Value Line Safety	S&P Bond Rating	Moody's Bond Rating
Unisource Energy	$975,000	84%	39%	3	NR	NR
Parcell Proxy Group						
Avista Corp.	$1,000,000	53%	54%	3	BBB+	Baa1
Hawaiian Electric Industries, Inc.	$1,600,000	98%	46%	3	BBB	Baa2
Northeast Utilities	$3,600,000	81%	41%	3	BBB+	A3
Pinnacle West Capital Corp.	$3,300,000	97%	45%	3	BBB-	Baa2
Pepco Holdings, Inc.	$3,100,000	50%	43%	3	A-	Baa1
TECO Energy, Inc.	$2,800,000	63%	39%	3	BBB	Baa1
Westar Energy, Inc.	$2,300,000	71%	44%	2	BBB-	Baa2
Pritz Comparable Company Group						
ALLETE, Inc.	$1,100,000	90%	58%	2	A-	A2
CH Energy Group, Inc.	$750,000	49%	49%	1	A	A2
Empire District Electric Co.	$625,000	86%	43%	3	BBB+	Baa1
Hawaiian Electric Industries	$1,600,000	98%	46%	3	BBB	Baa2
MGE Energy, Inc.	$850,000	59%	64%	1	AA-	Aa2
Northeast Utilities	$4,100,000	81%	41%	3	BBB+	A3
NorthWestern Corp.						
NSTAR	$3,400,000	80%	43%	1	AA-	A1
Portland General Electric	$1,400,000	98%	49%	2	A	Baa1
UIL Holdings	$775,000	100%	45%	2	NR	Baa2

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	July -- September, 2009 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group						
Avista Corp.	$0.21	$0.84	$20.83	$17.59	$19.21	4.4%
Hawaiian Electric Industries, Inc.	$0.31	$1.24	$19.45	$16.50	$17.98	6.9%
Northeast Utilities	$0.24	$0.95	$24.78	$21.11	$22.95	4.1%
Pinnacle West Capital Corp.	$0.53	$2.10	$33.71	$28.87	$31.29	6.7%
Pepco Holdings, Inc.	$0.27	$1.08	$15.37	$12.85	$14.11	7.7%
TECO Energy, Inc.	$0.20	$0.80	$14.64	$11.16	$12.90	6.2%
Westar Energy, Inc.	$0.30	$1.20	$21.56	$17.91	$19.74	6.1%
Average						**6.0%**
Pritz Comparable Company Group						
ALLETE, Inc.	$0.44	$1.76	$34.57	$27.75	$31.16	5.6%
CH Energy Group, Inc.	$0.54	$2.16	$51.32	$43.67	$47.50	4.5%
Empire District Electric Co.	$0.32	$1.28	$19.00	$16.44	$17.72	7.2%
Hawaiian Electric Industries	$0.31	$1.24	$19.45	$16.50	$17.98	6.9%
MGE Energy, Inc.	$0.37	$1.47	$38.23	$33.40	$35.82	4.1%
Northeast Utilities	$0.24	$0.95	$24.78	$21.11	$22.95	4.1%
NorthWestern Corp.	$0.34	$1.34	$24.94	$22.58	$23.76	5.6%
NSTAR	$0.38	$1.50	$32.91	$30.10	$31.51	4.8%
Portland General Electric	$0.26	$1.02	$20.95	$17.69	$19.32	5.3%
UIL Holdings	$0.43	$1.73	$27.48	$21.72	$24.60	7.0%
Average						**5.5%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2012-'14	Average
Parcell Proxy Group										
Avista Corp.	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	2.5%	3.3%
Hawaiian Electric Industries, Inc.	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	2.5%	1.3%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
Pinnacle West Capital Corp.	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	0.5%	2.0%	3.0%	1.8%
Pepco Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	0.5%	2.5%	3.0%	2.0%
TECO Energy, Inc.	0.0%	3.3%	5.0%	5.1%	0.0%	2.7%	2.5%	3.5%	4.5%	3.5%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	2.5%	3.0%	3.0%	2.8%
Average						**2.4%**				**2.7%**
Pritz Comparable Company Group										
ALLETE, Inc.	4.7%	5.2%	5.0%	5.8%	3.9%	4.9%	0.5%	1.5%	2.5%	1.5%
CH Energy Group, Inc.	1.7%	2.0%	1.2%	1.6%	0.4%	1.4%	0.5%	1.0%	2.0%	1.2%
Empire District Electric Co.	0.0%	0.0%	0.8%	0.0%	0.0%	0.2%	1.0%	1.5%	3.0%	1.8%
Hawaiian Electric Industries	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	2.5%	1.3%
MGE Energy, Inc.	2.3%	1.2%	3.7%	4.3%	4.4%	3.2%	5.0%	4.5%	5.5%	5.0%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
NorthWestern Corp.	--	4.2%	0.8%	0.7%	2.3%	2.0%				
NSTAR	4.8%	4.6%	4.9%	4.9%	4.9%	4.8%	5.0%	5.0%	6.0%	5.3%
Portland General Electric	7.2%	5.3%	3.5%	6.6%	2.0%	4.9%	2.0%	3.5%	3.5%	3.0%
UIL Holdings	0.0%	0.0%	0.0%	3.1%	1.0%	0.8%	1.0%	1.5%	2.5%	1.7%
Average						**2.6%**				**2.8%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '06-'08 to '12-'14 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
Avista Corp.	4.0%	5.0%	3.0%	4.0%	6.5%	11.5%	3.0%	7.0%
Hawaiian Electric Industries, Inc.	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
Pinnacle West Capital Corp.	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	2.0%	NMF	2.0%	2.0%
TECO Energy, Inc.	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Westar Energy, Inc.	21.5%	-0.5%	1.0%	7.3%	4.5%	4.5%	6.0%	5.0%
Average				**2.2%**				**4.1%**
Pritz Comparable Company Group								
ALLETE, Inc.	--	--	--		-1.0%	3.0%	3.0%	1.7%
CH Energy Group, Inc.	-1.5%	0.0%	1.5%	0.0%	3.0%	0.0%	1.5%	1.5%
Empire District Electric Co.	3.5%	0.0%	1.5%	1.7%	6.0%	1.5%	2.0%	3.2%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
MGE Energy, Inc.	6.0%	1.0%	8.0%	5.0%	6.0%	0.5%	7.0%	4.5%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
NorthWestern Corp.	--	--	--		23.0%	3.0%	0.5%	8.8%
NSTAR	4.0%	6.0%	5.0%	5.0%	8.0%	5.5%	5.5%	6.3%
Portland General Electric	--	--	--		3.5%	5.5%	2.5%	3.8%
UIL Holdings	--	--	-2.0%	-2.0%	3.0%	0.0%	2.5%	1.8%
Average				**1.8%**				**4.1%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Avista Corp.	4.5%	2.6%	3.3%	4.0%	7.0%	8.7%	5.1%	9.6%
Hawaiian Electric Industries, Inc.	7.0%	0.9%	1.3%		3.0%	3.0%	2.1%	9.0%
Northeast Utilities	4.3%	2.6%	4.3%	4.5%	6.5%	8.5%	5.3%	9.5%
Pinnacle West Capital Corp.	6.8%	1.9%	1.8%	2.3%	1.7%	5.5%	2.6%	9.4%
Pepco Holdings, Inc.	7.8%	2.6%	2.0%	5.7%	2.0%	5.5%	3.5%	11.3%
TECO Energy, Inc.	6.3%	2.7%	3.5%		3.8%	8.4%	4.6%	10.9%
Westar Energy, Inc.	6.2%	3.7%	2.8%	7.3%	5.0%	3.3%	4.4%	10.7%
Mean	6.1%	2.4%	2.7%	4.8%	4.1%	6.1%	4.0%	**10.1%**
Median	6.3%	2.6%	2.8%	4.5%	3.8%	5.5%	4.4%	**9.6%**
Composite - Mean		**8.6%**	8.9%	10.9%	10.3%	**12.3%**	10.1%	
Composite - Median		**8.9%**	9.2%	10.8%	10.2%	**11.8%**	10.8%	
Pritz Comparable Company Group								
ALLETE, Inc.	5.7%	4.9%	1.5%		1.7%	6.0%	3.5%	9.3%
CH Energy Group, Inc.	4.6%	1.4%	1.2%		1.5%	N/A	1.3%	5.9%
Empire District Electric Co.	7.3%	0.2%	1.8%	1.7%	3.2%	6.0%	2.6%	9.9%
Hawaiian Electric Industries	7.0%	0.9%	1.3%		3.0%	3.0%	2.1%	9.0%
MGE Energy, Inc.	4.2%	3.2%	5.0%	5.0%	4.5%	5.0%	4.5%	8.7%
Northeast Utilities	4.3%	2.6%	4.3%	4.5%	6.5%	8.5%	5.3%	9.5%
NorthWestern Corp.	5.8%	2.0%			8.8%	8.8%	6.5%	12.4%
NSTAR	4.9%	4.8%	5.3%	5.0%	6.3%	5.5%	5.4%	10.3%
Portland General Electric	5.4%	4.9%	3.0%		3.8%	7.4%	4.8%	10.2%
UIL Holdings	7.1%	0.8%	1.7%		1.8%	4.4%	2.2%	9.3%
Mean	5.6%	2.6%	2.8%	4.0%	4.1%	6.1%	3.8%	**9.5%**
Median	5.6%	2.3%	1.8%	4.8%	3.5%	6.0%	4.0%	**9.4%**
Composite - Mean		**8.2%**	8.4%	9.7%	9.7%	**11.7%**	9.5%	
Composite - Median		7.9%	**7.4%**	10.3%	9.1%	**11.6%**	9.6%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.18	$529.59	12.50%	4.86%	7.64%
2008	$14.88				
Average					**6.44%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit___(DCP-1)
Schedule 9

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Avista Corp.	4.28%	0.70	5.32%	8.0%
Hawaiian Electric Industries, Inc.	4.28%	0.70	5.32%	8.0%
Northeast Utilities	4.28%	0.70	5.32%	8.0%
Pinnacle West Capital Corp.	4.28%	0.75	5.32%	8.3%
Pepco Holdings, Inc.	4.28%	0.80	5.32%	8.5%
TECO Energy, Inc.	4.28%	0.85	5.32%	8.8%
Westar Energy, Inc.	4.28%	0.75	5.32%	8.3%
Mean				**8.3%**
Median				**8.3%**
Pritz Comparable Company Group				
ALLETE, Inc.	4.28%	0.70	5.32%	8.0%
CH Energy Group, Inc.	4.28%	0.65	5.32%	7.7%
Empire District Electric Co.	4.28%	0.75	5.32%	8.3%
Hawaiian Electric Industries	4.28%	0.70	5.32%	8.0%
MGE Energy, Inc.	4.28%	0.65	5.32%	7.7%
Northeast Utilities	4.28%	0.70	5.32%	8.0%
NorthWestern Corp.	4.28%	0.00	5.32%	4.3%
NSTAR	4.28%	0.65	5.32%	7.7%
Portland General Electric	4.28%	0.75	5.32%	8.3%
UIL Holdings	4.28%	0.70	5.32%	8.0%
Mean				**7.6%**
Median				**8.0%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
7/1/2009	4.38%
8/1/2009	4.33%
9/1/2009	4.14%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	1992-2001 Average	2002-2009 Average	2010	2012-14
Parcell Proxy Group																						
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.1%	10.4%	6.3%	8.0%	8.0%
Hawaiian Electric Industries, Ir	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	7.5%	11.0%	9.2%	9.5%	10.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	9.6%	3.8%	7.1%	9.5%	8.5%
Pinnacle West Capital Corp.	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.9%	11.5%	7.8%	8.0%	9.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	6.3%	11.0%	8.1%	8.0%	8.0%
TECO Energy, Inc.	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	11.0%	15.6%	10.5%	11.5%	12.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	8.2%	6.7%	8.6%	8.5%	8.0%
Average	11.9%	11.8%	11.5%	11.8%	10.1%	7.9%	9.0%	6.9%	9.1%	9.8%	8.5%	7.2%	7.5%	8.5%	9.2%	8.7%	7.9%	**8.2%**	**10.0%**	**8.2%**	**9.0%**	**9.1%**
Median	11.0%	12.0%	10.8%	11.1%	10.6%	10.9%	11.3%	11.1%	9.8%	11.9%	8.6%	7.6%	8.2%	8.1%	9.2%	8.5%	7.6%	**8.1%**	**11.1%**	**8.2%**	**8.5%**	**8.5%**
Pritz Comparable Company Group																						
ALLETE, Inc.														12.0%	13.2%	13.4%	11.4%	7.6%		11.5%	8.0%	9.0%
CH Energy Group, Inc.	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	8.9%	7.9%	8.2%	6.7%	6.6%	9.5%	7.9%	7.0%	8.0%
Empire District Electric Co.	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	9.6%	8.6%	7.8%	9.5%	10.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	7.5%	11.0%	9.2%	9.5%	10.0%
MGE Energy, Inc.	13.1%	13.3%	13.1%	12.5%	7.1%	12.5%	12.2%	13.0%	14.2%	13.1%	13.2%	12.5%	11.4%	9.4%	11.9%	12.1%	11.8%	11.2%	12.1%	11.7%	11.0%	12.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	9.6%	3.8%	7.1%	9.5%	8.5%
NorthWestern Corp.																						
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	13.5%	13.6%	13.7%	12.7%	13.6%	14.0%	14.5%
Portland General Electric	12.9%	12.0%	11.3%	13.4%	13.9%										5.9%	11.5%	6.5%	6.4%	12.7%	7.6%	8.0%	8.5%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	9.9%	9.7%	8.4%	10.0%	10.5%
Average	11.4%	11.0%	11.5%	11.4%	9.4%	8.7%	9.4%	8.4%	9.8%	10.6%	10.0%	9.8%	8.7%	8.8%	9.4%	10.2%	9.4%	9.1%	**10.0%**	**9.4%**	**9.6%**	**10.2%**
Median	11.2%	10.8%	11.2%	11.4%	10.3%	10.9%	11.5%	11.1%	10.5%	12.1%	8.9%	9.1%	8.7%	9.2%	9.2%	10.1%	9.8%	9.6%	**11.1%**	**9.3%**	**9.5%**	**10.0%**

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	1992-2001 Average	2002-2009 Average
Parcell Proxy Group																				
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	88%	163%	108%
Hawaiian Electric Industries,	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	114%	147%	163%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	112%	118%	118%
Pinnacle West Capital Corp.	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	86%	136%	117%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	150%	113%
TECO Energy, Inc.	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	116%	235%	167%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	87%	118%	115%
Average	163%	168%	141%	146%	150%	149%	160%	144%	166%	138%	109%	111%	134%	149%	151%	150%	128%	97%	**152%**	**129%**
Median	154%	154%	133%	129%	145%	151%	161%	143%	139%	129%	110%	109%	130%	130%	135%	141%	115%	88%	**144%**	**120%**
Pritz Comparable Company Group																				
ALLETE, Inc.													322%	212%	219%	195%	156%	113%	203%	203%
CH Energy Group, Inc.	123%	133%	107%	112%	114%	135%	155%	133%	125%	141%	152%	147%	149%	146%	154%	145%	132%	133%	135%	145%
Empire District Electric Co.	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	122%	99%	150%	135%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	114%	147%	163%
MGE Energy, Inc.	189%	196%	189%	183%	203%	189%	197%	177%	172%	197%	214%	223%	207%	207%	191%	178%	160%	151%	190%	191%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	112%	118%	118%
NorthWestern Corp.																				
NSTAR	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	222%	201%	187%	170%	195%
Portland General Electric	115%	125%	112%	140%	199%										153%	140%	101%	80%	138%	119%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	126%	139%	146%
Average	150%	156%	135%	138%	142%	133%	157%	149%	149%	153%	150%	148%	179%	167%	175%	172%	148%	124%	**154%**	**157%**
Median	146%	154%	129%	135%	134%	138%	155%	144%	141%	145%	152%	147%	164%	165%	174%	166%	156%	114%	**142%**	**155%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2007

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
Averages:		
1992-2001	14.7%	341%
2002-2007	13.9%	284%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

Exhibit___(DCP-1)
Schedule 12

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.9	0.75	B+	B
Pritz Comparable Company Group	2.0	0.69	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit___(DCP-1)
Schedule 13

UNS ELECTRIC INC
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	54.24%	7.05%	3.82%	3.82%	
Common Equity	45.76%	10.00%	4.58%	7.63%	
Total	100.00%		8.40%	11.45%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **2.99**
11.58% /3.25%

Standard & Poor's Utility Benchmark Ratios: Business Profile of "4"	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP	Year	Real GDP	GDP Index	Nominal GDP
2008	2.3%	2.0%	4.3%	2049	2.2%	2.4%	4.6%
2009	2.8%	2.1%	4.9%	2050	2.1%	2.4%	4.5%
2010	2.7%	2.4%	5.1%	2051	2.1%	2.4%	4.5%
2011	2.5%	2.4%	4.9%	2052	2.1%	2.4%	4.5%
2012	2.5%	2.4%	4.9%	2053	2.1%	2.4%	4.5%
2013	2.5%	2.4%	4.9%	2054	2.1%	2.4%	4.5%
2014	2.4%	2.4%	4.8%	2055	2.1%	2.4%	4.5%
2015	2.3%	2.4%	4.7%	2056	2.1%	2.4%	4.5%
2016	2.3%	2.4%	4.7%	2057	2.1%	2.4%	4.5%
2017	2.3%	2.4%	4.7%	2058	2.1%	2.4%	4.5%
2018	2.3%	2.4%	4.7%	2059	2.1%	2.4%	4.5%
2019	2.3%	2.4%	4.7%	2060	2.1%	2.4%	4.5%
2020	2.2%	2.4%	4.6%	2061	2.1%	2.4%	4.5%
2021	2.2%	2.4%	4.6%	2062	2.1%	2.4%	4.5%
2022	2.2%	2.4%	4.6%	2063	2.1%	2.4%	4.5%
2023	2.2%	2.4%	4.6%	2064	2.1%	2.4%	4.5%
2024	2.2%	2.4%	4.6%	2065	2.1%	2.4%	4.5%
2025	2.1%	2.4%	4.5%	2066	2.1%	2.4%	4.5%
2026	2.1%	2.4%	4.5%	2067	2.1%	2.4%	4.5%
2027	2.1%	2.4%	4.5%	2068	2.1%	2.4%	4.5%
2028	2.1%	2.4%	4.5%	2069	2.1%	2.4%	4.5%
2029	2.1%	2.4%	4.5%	2070	2.1%	2.4%	4.5%
2030	2.1%	2.4%	4.5%	2071	2.1%	2.4%	4.5%
2031	2.1%	2.4%	4.5%	2072	2.1%	2.4%	4.5%
2032	2.1%	2.4%	4.5%	2073	2.1%	2.4%	4.5%
2033	2.1%	2.4%	4.5%	2074	2.1%	2.4%	4.5%
2034	2.1%	2.4%	4.5%	2075	2.1%	2.4%	4.5%
2035	2.2%	2.4%	4.6%	2076	2.1%	2.4%	4.5%
2036	2.2%	2.4%	4.6%	2077	2.1%	2.4%	4.5%
2037	2.2%	2.4%	4.6%	2078	2.1%	2.4%	4.5%
2038	2.2%	2.4%	4.6%	2079	2.1%	2.4%	4.5%
2039	2.2%	2.4%	4.6%	2080	2.1%	2.4%	4.5%
2040	2.2%	2.4%	4.6%	2081	2.1%	2.4%	4.5%
2041	2.2%	2.4%	4.6%	2082	2.1%	2.4%	4.5%
2042	2.2%	2.4%	4.6%				
2043	2.2%	2.4%	4.6%				
2044	2.2%	2.4%	4.6%				
2045	2.2%	2.4%	4.6%				
2046	2.2%	2.4%	4.6%				
2047	2.2%	2.4%	4.6%	Average			**4.6%**
2048	2.2%	2.4%	4.6%				

Source: 2007 OASDI Trustees Report.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Energy Information Administration

Annual Growth (2005-2030):

Real GDP	2.4%
GDP Chain-type Price Index	2.0%
Nominal GDP Growth	**4.4%**

Source: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

DIRECT

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

The Direct Testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. ("WML&A") presents the evaluations of UniSource Electric ("UNS Electric" "UNSE" or "Company") distribution system reliability and service quality, in service operations and facility investments, facilities proposed for inclusion into rate base that include new distribution facilities with differing standards of construction than those acquired from Citizen's Power Company. Additionally, our evaluations included the field investigation, and discussion with on-site personnel, of the Black Mountain Generation Station ("BMGS") proposed for purchase by the Company from UniSource Energy Development Company. The Company is requesting that the Commission approve the BMGS as a post-test year adjustment to rate base. Our conclusions are based upon field investigations, discussions with UNS Electric and Tucson Electric Power ("TEP") personnel, and UNS Electric responses to data requests submitted by the Arizona Corporation Commission ("Commission") Staff.

Quality of Service/Distribution Indices

The service quality and reliability of the UNS Electric distribution system was evaluated by analysis of the reliability indices for calendar years 2007 and 2008, and for the initial eight months of 2009. The determinations of the indices were discussed with TEP personnel during our field investigation, and provided in response to a Commission Staff data request. The indices evaluated are Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). Our review and analysis of the outage data and determinations indicate that the distribution system provides service quality and reliability comparable to an average to somewhat below average electric utility system of similar size and service area characteristics. We noted that the indices for "Major Event Days" which are periods of significant adverse weather, grid outages, or other system disruptions were not a source of lower service quality as might be expected. Our discussions with TEP personnel who had evaluated the indices suggested to us that this was their initial compilation of the indices. There is, however, a plan to initiate routine collections and analyses of service quality indices that will be considered by UNS Electric management in the very near future.

Facilities Investment/In-Service Operations

Our field investigations included the Call Center where customers report outages, service and billing problems. The Call Center operates effectively as a means of notification to maintenance personnel of the need to respond to outages and other network problems reported by electric, as well as gas customers. Electric maintenance personnel are separate from gas maintenance personnel. The integration of the Call Center with the maintenance facilities and dispatching of personnel (troublemen) affects the duration of outages in a significant manner. We found the Call Center, which also receives outage and bill calls for TEP, to be an efficient and effective means of customer contact and maintenance notification.

In evaluating the effectiveness of UNS Electric grid and distribution operations, we investigated system losses and power factors of the UNS Electric distribution system. The distribution losses and the average and peak power factor data were provided as a response to Commission Staff data requests. We determined that the UNS Electric system distribution losses were in line with similar utility performance as were the power factors. We also reviewed the number and placement of capacitors for power factor correction on the UNS Electric system, and found both to be in keeping with accepted utility practices. UNS Electric studies of the distribution and transmission systems were performed by TEP personnel on an "as-needed" basis. We found this approach to be an acceptable means of addressing periodic needs for such studies.

Field investigations of the major distribution substations installed prior to and after the acquisition of the Citizens system by UNS were made to assess their standards of construction and suitability for inclusion into rate base. In addition, we considered whether there was a pressing need to bring the acquired facilities into conformance with TEP standards to assure proper maintenance and performance. Our investigations and observations of these facilities, and subsequent repairs and replacements that had been made by UNS Electric already, indicated that the facilities were properly functional and that any divergence from TEP standards would not constitute any impairment to the on-going maintenance activities. We also concluded that the facilities we observed and proposed for inclusion into rate base were complete and in-service.

Field observations of two generating facilities were also made. These included the existing Valencia Generating Station located in the Santa Cruz service area which had been improved by the addition of Unit #4 gas turbine set and substation upgrades, and the BMGS located in the Mohave service area. The BMGS facility is a two unit gas turbine station which is proposed for acquisition by UNS Electric and currently operated by UNS Electric personnel. We found the Valencia improvements and its Unit #4 to be properly installed, in-service, and well maintained. As for BMGS, we observed that one of its two units had recently been damaged by numerous blade failures and was currently being evaluated as to the extent of the damage and necessary repairs. Both of the two units have been previously operated and provided generation for about 15 months prior to this failure. Further observations of the common facilities and substation at BMGS indicated that the site is suitable for future expansion and that the facilities are well maintained. We subsequently questioned if the site auxiliaries could support the continuous operation of both units at rated output for extended periods of time. UNS Electric responded to a Commission Staff data request that there are emissions limitations, but did not indicate any other limiting factors, such as water treatment capacity. We have stated in the testimony that UNS Electric should discuss this aspect further in subsequent testimony.

Our recommendations to the Commission include:

1. The Commission should require an annual report of the distribution indices including a listing of the worst performing circuits and what steps are being taken to mitigate these circuits poor performance by UNS. The report should be separated by service area and by the results for the overall UNS system. Other requirements for this report should conform to those required of Arizona Public Service as described in the current settlement proceedings.

2. The Company states in response to STF 8.1 that they invested approximately $86 million of new plant since the end of the last test year. WML&A reviewed the major plant additions which I discuss in my testimony. Of the plant items we inspected, we found that they were well constructed, functioning at expected levels, and are presently being used for the provision of service to rate payers. Therefore, we recommend that the portion of plant items completed and used and useful at the end of the test year in this proceeding be included in this rate case.

3. Currently, BMGS is owned by UniSource Energy Development ("UED"), however, our inspection of the BMGS facility indicates that the facility is properly constructed and should be back to full operational levels once the repairs are made by UED.

4. At such time if and when UNSE acquires the BMGS, any costs of repair not covered by warranty should be borne by UED and not by UNSE at the time of purchase.

5. If UNSE ultimately acquires BMGS, UNSE should be required to demonstrate to the Commission that there are no limitations due to water availability on the required operations of both Unit #1 and Unit #2.

6. UNS Electric's maintenance scheduling at the BMGS Facility should include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, if it ultimately acquires the facility.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. What is your present employment?

A. I am employed by the firm of W. M. Lewis and Associates, Inc. ("WML&A"). I am the President of the firm.

Q. Please describe the nature of the firm.

A. WML&A is a Consulting Engineering firm which provides various engineering services, primarily in areas of electrical power and electric utility operation, to a range of clients including investor-owned electric utilities, municipal utilities, international investment organizations, and regulatory bodies. The firm was established in 1958.

Q. Please describe your background, education, and experience.

A. I have been employed by WML&A since 1979. Prior employment was with Goodyear Atomic Corp. and Westinghouse Electric. Positions that I have held at WML&A include Sr. Engineer, Manager of Engineering, Vice-President, and President. I hold a BSEE degree from Ohio State University and an MBA from Ohio University. For the past 15 years, much of my work has involved foreign assignments on behalf of the Asian Development Bank and World Bank in project post-evaluation, feasibility studies, and reviews of operation and maintenance of various generating stations, urban and rural transmission and distribution systems, and utility management. Additional tasks included the design of facilities and preparation of agreements for the interconnection of utilities, preparing operating agreements between utilities and independent power producers, and various tasks related to the privatization of electric utilities in the South Asian area. Additional aspects of my experience and education are presented in my resume, which is attached to this testimony as Attachment 1.

Q. Are you filing direct testimony on behalf of Arizona Corporation Commission ("Commission") Staff?

A. Yes.

Q. What is the nature of your testimony in this proceeding?

A. My testimony describes and presents evaluations, observations and recommendations regarding the above captioned matter. We were to evaluate the service quality and reliability of the distribution system, observe and evaluate some of the major items of investment proposed for post test year inclusion into rate base as to their status, evaluate the comparative standards of construction between the acquired system and subsequent installations, and to observe the facilities of the Black Mountain Generating Station ("BMGS") as to construction quality.

Q. What was the major component of your evaluation?

A. Consistent with the authorization and in concert with Commission Staff direction, a major component of the investigation was the field inspections of UniSource Electric, Inc. ("UNS Electric," "UNSE," or "Company") facilities in the Tucson, Kingman, and Nogales areas. Field inspections were made on October 5, 2009 through October 8, 2009 accompanied by UNS Electric and Tucson Electric Power ("TEP") personnel.

Q. Who participated in the field investigations with you?

A. I performed the field inspections with the assistance of Kenneth Strobl, P.E. of the firm of Technical Associates, Inc. Mr. Strobl also contributed to the preparation of this testimony.

Q. Please describe the major elements of your investigations.

A. The major elements of our investigation focus on UNS Electric's service quality, distribution system indices, and the operations of selected generation, transmission, and distribution facilities currently in service. The field inspections included discussions with the Company engineering and other technical personnel, as well as control room and shift operators who monitor and operate the Company's generation assets and its electrical transmission and distribution network assets. In anticipation of, and in conjunction with, these activities, we also reviewed portions of UNS Electric's prefiled Application and testimony in this case, as well as public documents such as its Federal Energy Regulatory Commission ("FERC") Form 1. Additionally, we prepared data requests to the Company that addressed service quality, electric distribution and generation system operations. Upon review of responses and discussions with UNS Electric and TEP personnel, follow-up data requests were prepared and submitted to the Company as well.

Q. What were the impacts of these efforts?

A. The field inspections, the discussions with UNS Electric and TEP personnel, the reviews of UNS Electric-filed documentation in this case and public documents, and the discussions with Commission Staff provided some understanding of the Company's installations and operations of its electrical network assets in Arizona. Accordingly, the remainder of this testimony discusses these observations and evaluations, and provides recommendations to the Commission regarding operations of the UNS Electric network assets. This testimony also contains our comments regarding the Company's personnel we met in our field visits that are charged with ensuring that system operations are safe, reliable, and meet the electrical service needs of the Company's customers.

II. WORK ACTIVITIES AND EVALUATIONS

Q. Please describe your evaluations and the role of your field investigations.

A. Our work activities began with reviews and analyses of UNS Electric's Application and prefiled testimony and exhibits in this proceeding. In addition to the information in the Application and prefiled materials, we reviewed the Company's Annual Reports, FERC Form No. 1 and supplemental documents filed in support of the Application.

Additional information was acquired and analyses undertaken through UNS Electric responses to data requests issued by the Commission Staff, in particular Commission Staff requests, STF 8, STF 9 and STF 15. Responses to STF 8 data requests addressed the Company's Construction Work in Progress ("CWIP") projects being requested for rate base treatment, which included an itemization of project investments and their corresponding in-service dates. Additionally, responses to Commission Staff data requests STF 8 and STF 9 provided information regarding the Company's distribution system performance, operations, and reliability, call center and maintenance dispatch procedures, and operations of the BMGS facility. BMGS is currently owned by UNS Energy Development Company, with UNS Electric requesting in this case that it be allowed to acquire the facility and include it in rate base.

UNS Electric responses to STF 9 and STF 15 provided operational information regarding the Valencia generating facility, and operating and maintenance data regarding the monitoring of the Company's overhead lines and substation facilities. Additionally, the Company's response to STF 15 addressed operational aspects of the Western Area Power Administration ("WAPA") interconnections with UNS Electric, and operating and performance measures regarding the Valencia and Black Mountain generating facilities.

A. Quality of Service/Distribution Performance

Q. Please discuss the determination of the Company's Quality of Service as it relates to Distribution Performance.

A. The electric utility industry has developed various indices as indicators of distribution performance and reliability. These include measures of customer average outage duration and average frequency of outages. These indices are defined by IEEE standard P1366 which has set a 5-minute disruption of service as the threshold to be considered an outage for the calculation of the various indices. In 2003, IEEE-1366 included the concept of a "Major Event Day" ("MED") to account for outages deemed to be caused by unusually severe weather and similar incidents so that such incidents could be considered separately from normal operating conditions. MED thresholds are calculated on a 5-year (rolling) average. The indices of most concern are "Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). In Data Request STF 8.9, we requested that the Company furnish the values of these three indices for the years of 2007, 2008, and to date for 2009. We also requested that the Company indicate the four worst performing circuits in both the Mohave and Santa Cruz service areas based upon their indices. Prior to receiving the Company's response, we discussed their progress and preliminary results with the Company representatives in a meeting on October 5, 2009 as a part of our field investigations.

Q. Was this data then furnished to you by the Company?

A. Yes, and the response is included here as Attachment 2.

Q. Please describe the nature of the Company's response.

A. The Company's response included the results for SAIFI and CAIDI for each of the service areas with the Mohave area separated into the Kingman and Lake Havasu areas together with the same two indices for the UNS Electric combined system. Included were the results for 2007, 2008, and 2009 through August 31 as we had requested. In addition, the two indices were presented for MED periods, normal or "clear weather" periods, and for the total time-period indicated. SAIDI results were not furnished nor were the requested worst circuits indicated.

Q. Is the absence of the SAIDI calculations an impairment to your evaluation?

A. No. The SAIDI index value is, in fact, the product of SAIFI times CAIDI so that the value can be calculated from the values provided.

Q. What about not having the "worst performing circuits" provided?

A. The purpose in our request for these circuit identifications was to evaluate the effect of those outages on the over-all system results, to know the cause of the outages, and what (if any) mitigation efforts had been made or were planned to minimize those outages and thus, reduce the overall system indices values.

Q. What was the Company's reason for not providing the circuit designations?

A. As was stated by Company personnel during our discussion meeting and in the Company's response, indices are not calculated for any of the three service areas at a circuit level, therefore, the Company could not furnish that criteria.

Q. How do you interpret that response?

A. I have taken their responses to mean that outage data by specific circuit is not available or that the Company did not calculate a separate index for each distribution circuit.

Q. Has the Company been determining these indices in the past?

A. It was our impression from our discussions that this response is the first time that the Company has performed such an analysis. However, we were made to understand that the personnel preparing this response is also preparing a recommendation to present to Company management that an on-going program for the collection of outage data and indices determination per IEEE 1366 for the UNS distribution system be initiated along the lines as is presently performed by TEP for its system.

Q. Would you recommend that these determinations be initiated by the Company?

A. Certainly. Further, we will be recommending to the Commission that as a result of this proceeding, the Company should be required to submit a report along the lines of our Data Request to the Commission for review on an annual basis. We believe that such reporting is currently required of TEP and Arizona Public Service.

Q. What are the physical features of a distribution system that affect its indices?

A. The values of SAIFI, i.e., the frequency of outages to an average customer, are affected by the circuit configuration, circuit lengths, and the relative severity of lightning and weather events in the service area. In general, overhead radial circuits tend to have a higher frequency of outages as compared to network or looped configurations. Longer line lengths tend to have more exposure to various physical damage such as wind, ice, birds, etc. and, obviously, the greater the number of lightning strikes in a given area, the greater the likelihood of an outage; even more so for longer line lengths. CAIDI values, i.e., the duration of an outage to an average customer, is affected by the physical size and terrain of the service area, as that tends to increase the distance between the cause of the outage and the location of repair personnel. The availability of replacement equipment and their placement can also have an adverse effect.

Q. Given your observations of the service areas and facilities of the Company, what aspects would affect its performance?

A. The Company's typical circuit configuration is of overhead radial design which is well suited for its customer base and density. However, as stated above, that configuration tends to be less reliable than others. In addition, all of the three service areas include extensive rural areas where customers are remote from the central maintenance facilities, and most likely, from the assigned "troubleman" who will be charged with responding to reported outages. The nature of the service areas and the circuit configurations would tend to result in elevated indices values for both frequency and duration of outages. In addition, the southwest areas of the country are recognized as having high lightning frequency and those are of above average intensity. This also tends to increase outage frequency in the UNS Electric's service areas. However, the Lake Havasu service area appears to be less rural and more compact for the majority of its customer base.

Q. Is the different condition of the Lake Havasu service area reflected in the resulting indices values?

A. Yes, the reported indices are more favorable in the Lake Havasu area.

Q. Please continue.

A. As described above, the Company furnished SAIFI and CAIDI values separately for the three service areas, the combined Mohave County area, and the UNSE system. Taking the values for 2008 as a typical example (please refer to Attachment 2), the Lake Havasu results for both SAIFI and CAIDI for the "All" conditions are significantly lower than those for either Kingman or Santa Cruz. This would be expected given the service areas.

Q. How do the indices for UNSE compare to those of other utilities of similar size, service areas, and circuit configurations and how would you make such a comparison?

A. A basic comparison can be made by considering the values for SAIDI for the "All" conditions. As mentioned above, the value for SAIDI is the mathematical produce of the values for the listed SAIFI and CAIDI. For UNSE values in 2007, the SAIDI would be calculated as 1.586 X 65.860 = 104.45. Recent surveys indicate that for utilities of similar size and generally rural, dispersed service areas, an SAIDI of 60-80 would be indicative of an "upper third" performance, while a "median" performance would fall in the 80-100 range and the "lower third" tier of utilities would have an SAIDI of 120-140 and above.

Q. Was the 2007 performance indicative of subsequent times?

A. No. The corresponding value for 2008 is 2.029 X 113.506 = 230.30 which is clearly a poor result in comparison to others. However, for the first 8 months of 2009, this value would be 2.011 X 42.565 = 85.60. This is bordering on the upper third of utility performance.

Q. What accounts for the improvement in 2009 to date compared to 2008?

A. While the frequency of outages to date for 2009 was very similar to that of 2008, the duration of average customer outages decreased from the 113.506 to 42.565, thus the much lower value for SAIDI.

Q. Was this evident for all of the service areas?

A. Yes, which may indicate that the decrease to date may be a seasonal effect. That could be determined when the Company files an annual report.

Q. What would you consider a reasonable result for the Company for SAIDI?

A. I would consider a value for SAIDI between 80-100 for the "All" case to be reasonable for the present with demonstrated improvement toward the lower end of that range to be reasonable.

Q. Do you believe that the Company requires a significant increase in O&M to attain and maintain SAIDI of between 80-100?

A. No. I believe that instituting a program of monitoring and evaluating outage reports and identifying the more problematic circuits with mitigation will result in improvements in the distribution reliability and performance indices and in customer satisfaction.

Q. Do you have any further comments as to the reported indices?

A. Yes. We noted that the reported SAIFI and CAIDI values for MED periods appear to be superior to the "Clear Weather" periods in many of the time periods and individual service areas and for UNSE. This is unexpected. This may be due to heavier staffing levels during weather events or some other reason. It may be that the appropriate Company witness could present the Company's comments on this result during presentation of testimony.

Q. What other aspects of the Company's operations and development would tend to improve its reliability indices?

A. As the Company continues to replace the older circuit facilities and standardize in its distribution substations, there should be a corresponding decrease in the frequency of outages and a decrease in restoration times.

Q. Would you recommend that any program of accelerated replacement to enhance the standardization be put into effect?

A. No. I would recommend that efforts toward revising circuit configurations, equipment types, etc. be accomplished in the course of normal maintenance and repair.

B. In Service Operations and Facilities Investment

Q. Please discuss the Company's CWIP investments and its request for inclusion of these in rate base in this proceeding.

A. In UNS Electric witness DeConcini's Direct Testimony filed April 30, 2009, the Company claims that it has "substantial used and useful plant" that reflects capital expenditures from June 30, 2006 through December 31, 2008 that are not reflected in current rates. In response to Commission Staff STF 8.1 (and STF 1.1), UNS Electric identifies these capital expenditures as $19,240,000 (2006), $37,582,000 (2007) and $29,664,000 (2008) for a total of $86,486,000. The Company supports its request for the inclusion of the $86.486 million in its response to STF 1.1 by listing hundreds of individual projects, the dollar amounts of each and the in-service dates. The Company's requests for inclusion of these investments in rate base reflect plant in-service through the end of the test year, December 31, 2008.

Q. Please continue.

A. One of the objectives of our field investigations of October 5 through October 8 was to observe many of the projects, and discuss them with the UNS Electric and TEP personnel responsible for their development and performance. Due to the limited time and resources available for the field investigations, we concentrated on the larger and most expensive projects that are contained in the list of $86 million of CWIP projects requesting to be included in rate base in this case. The full listing of the projects requested for inclusion were provided by Company in their response to data request STF 8.1. A copy of that response is included here as Attachment 3.

In addition to these projects, we visited the BMGS in the Kingman area, toured the facilities, and talked to the on-site personnel responsible for the operations of the two gas-fired turbines. The Company is separately requesting approval of the acquisition of the BMGS and that it be included in rate base as described in UNS Electric witness Grant's Direct Testimony filed April 30, 2009.

B.1 Call Center and Outage Response Operations

Q. Please describe the Company's call center and its response operations to outage and other trouble calls from customers.

A. We visited the call center operations in Tucson, on the site of TEP's Sundt generation station. This call center receives calls regarding both UNS Electric and UNS Gas service operations as well as those of Tucson Electric. The call center has a rotating staff of about 60 employees. Supervisors monitor all call center personnel that are discussing outages and other problems; e.g., bill inquiries, on a real-time basis. There are also personnel available in the call center room to assist operators with complaints and/or requests that need some additional information or help.

The call center manager accumulates and analyzes calls to this facility on a monthly basis based on a tracking of daily call volumes and subject matter. These statistics provide the call center with quantitative metrics to evaluate the efficiency and thoroughness of their operations. In addition to complaints made to UNS Electric by customers that involved claims of poor power quality, such as provided in response to Commission Staff data request STF 8.20 (Attachment 4) for the period January 1, 2008 through August 2009, the Company archives the audio recording of customer calls for 3 years.

Customer calls regarding outages and other service quality problems are immediately relayed to the Control Area Operations center for disposition and remedy. The call center personnel are also well aware of the potential geographic problems with responding to outages, such as in the Kingman area. The Kingman service area is very rural and travel times by repair crews (troublemen) can be much longer than in more urban areas. In this regard, the accuracy of outage information gathered by the call center personnel is even more critical to affective responses to calls from customers. Moreover, the call center manager has instituted a procedure such that all elderly/senior citizens have a "flag" on their accounts to alert personnel responding to an outage to be aware that extra assistance may be necessary. The dispatching process is described in some detail with regard to both the Mohave and Santa Cruz service areas in the Company's response to STF 8.11. (Attachment 5)

Q. What is the next step in the Company's responses to outages and other service quality problems?

A. The calls from customers reporting outages and other service quality problems that have been reported to the Control Area Operations are then dispatched to field service personnel with as much information as possible regarding the electrical circumstances and geographical location of the problem. This dispatching operation is part of the Company's network and grid control operations located in the same building as the call center operations.

UNS Electric personnel and vehicles are maintained for responses to customer outages and other problems in the Mohave and in the Santa Cruz service areas. Our discussions with Company personnel confirm the Company's responses to STF 8.10 and STF 8.11 in terms of the manpower (journeyman lineman, lineman/troublemen) and equipment available to respond to customer electrical service complaints. In the Mohave service area, there are personnel and vehicles dispatched either from the Kingman District or from the Havasu District. In all the areas (Kingman and Havasu Districts and in Santa Cruz) in other than "normal" business hours (as outlined in STF 8.10), there are qualified journeymen linemen and/or linemen/troublemen "on call" with their equipment to respond from their homes to the calls from customers. The other than "normal" hours include weekends and holidays.

Q. Referring back to the subject of distribution system performance, do you believe that the current call center and its procedures are adequate to maintain acceptable outage restoration in the Mohave service areas?

A. Yes, I do. While there may be a small delay while outage or trouble reports are transmitted to the Kingman/Lake Havasu facilities or assigned troubleman, duplicating a similar call center in the Mohave area would negate the overhead savings and efficiency of the present call center which would not justify the small time delay.

B.2 Electric Grid Operations

Q. Please describe the Company's Electric Grid Operations.

A. The Control Area Operations center monitors the Company's 69/230 KV ties with WAPA, and monitors and manages the operations of its 115 KV system. Telemetering between the control center and substations and generating stations is predominantly microwave and radio, with some fiber optics communications.

The Energy Management System ("EMS"), a Siemens software system, which monitors and controls the UNS Electric system has been upgraded and adopted for use by UNS Electric. UNS Electric has in-place multiple back-up power source facilities; e.g., generators, generating station facilities, etc. to support the EMS and the control center generally. Moreover, UNS Electric has a back-up control center facility located at another area of its system in the event the Control Area Operations center is for some reason unable to operate.

The EMS in this control center also controls the generating facilities in the Nogales area (Valencia) and in the Kingman area (BMGS). Bulk power transformers also are monitored in real-time from this facility. As indicated in the Company's response to STF 8.7, and verified in discussions with the control center personnel, there are no must run power requirements ("RMR") for the Mohave service area through 2008. Since 2006, however, RMR requirements have been in place for the Santa Cruz area. The Valencia generator (Santa Cruz area) start guideline is currently 51 MW (effective February 19, 2009). The Valencia generation starts had been based on a load of 65 MW or higher through the 2008 peak.

Q. Are you satisfied that the Control center will manage the UNS system in a reliable and adequate manner?

A. Yes.

B.3 Quality of Service/Distribution System

Q. What information was obtained and discussions undertaken through your field investigations regarding the reliability of the Company's distribution system operations?

A. We met with distribution system planning and technical (engineering) services personnel to discuss system reliability metrics and generally system planning efforts. These personnel are TEP employees who wear two hats, assigning their work hours to both TEP and UNS Electric depending on what projects they are working on.

Reliability Metrics. With regard to UNS Electric's distribution service quality indices, Section II.A. of this testimony describes the Company's analyses and the results of their evaluations of CAIDI, SAIDI and SAIFI for each of the non-contiguous UNS Electric service areas. The personnel with whom we discussed these analyses undertake the determinations of these evaluations for both UNS Electric and TEP. The results of their analyses for UNS Electric, however, are not submitted to the Commission.

Distribution System. Most of the current UNS Electric facilities are the Citizens electric utility system prior to the acquisition of Citizens by UniSource, the parent company of TEP. Accordingly, a principle effort of the Company is the integration of the UNS Electric plant and equipment facilities to more closely reflect those of TEP on an operational basis, as well as on a compatibility of network electrical components basis. UNS Electric personnel indicate that these efforts are, however, made more difficult by the remoteness and differences in the character of the non-contiguous service areas served by UNS Electric. UNS Electric develops a 5-year distribution system plan (as does TEP) and is working on developing more long-range plans, such as those prepared by TEP; i.e., 10-20 year plans.

In conjunction with its distribution system planning and responsibilities, the planning and technical services group also is cognizant of maintaining necessary interconnection facilities with WAPA and correspondingly sufficient available capacity on the WAPA transmission network. In this regard, maintaining a high power factor is an objective that has been addressed by UNS Electric over the years. In response to STF 8.16, UNS Electric states that power factor data are not available at the distribution system level. In the response, UNS Electric opines that since the Mohave and Santa Cruz distribution systems "operate as radial distribution systems" that the power factors at the point of delivery from the transmission system are "reasonable proxies for the overall distribution system." Calculated average power factors for each of the delivery points from WAPA to Mohave and Santa Cruz service areas show improvements in power factors from 2006 to 2008.

UNS Electric's objective of improvement in service area power factors and in system stability is supported by the Company's response to STF 8.19. The Company lists capacitor bank installations (at various KVAR levels) in the Kingman, Lake Havasu City and Santa Cruz Districts over the 2005-2008 time period (i.e., 52 capacitor additions and locations). Approximately 50 percent of the additions and locations of new capacitor bank installations were placed in-service in 2007 and 2008.

Q. What distribution system studies and analyses are undertaken by UNS Electric?

A. UNS Electric personnel indicated that they do not undertake harmonic studies, but do perform load-flow and short-circuit studies on individual distribution feeder circuits. In this regard, the Company's response to STF 8.18 outlines some of the reasons for load flow studies (e.g., reported voltage problems, load growth considerations, etc.), and for the short-circuit studies (e.g., provide data to facilitate electrical device protection), as well as the improvements that are implemented by UNS Electric based on these studies.

Q. Do you consider the current studies and analyses of the distribution system undertaken by UNS Electric adequate?

A. Yes. The needs of UNS Electric for studies and analysis are being adequately addressed given the current and expected levels of growth. In any event, UNS Electric's ability to engage the resources of TEP engineering when such needs arise gives assurance that analysis is available when required.

C. Mohave Service Area

Q. Please discuss the UNS Electric facilities you observed in the Mohave Service Area during your field investigation.

A. Our visit to the Mohave Service Area included observations of several substations, and the BMGS gas turbine units and the auxiliary equipment and attendant switchyard/substation at the BMGS site. As was the case with all our visits, we were accompanied by UNS Electric/TEP technical personnel knowledgeable about the operating functions of the electric facilities at the particular sites.

Q. Please discuss the characteristics and functions of the substation facilities you observed in the Mohave Service Area.

A. The substations we observed included in part older equipment and structures (Citizens installations) and in part UNS Electric upgrades. It was obvious from our visits to these substations that UNS Electric was making a concerted effort and commitment to standardization of equipment to limit its required inventory of parts and materials. As substantiated by the personnel who accompanied us, these efforts are focused on developing a more standard substation layout across the UNS Electric system, and to be more compatible with TEP's substation equipment and structures. Accordingly, at this time, there is no reason to recommend to the Commission that UNS Electric undertake any dramatic efforts in this regard. In our opinion, UNS Electric should continue with these efforts since they would seem to be the technologically (and economically) reasonable avenues to pursue.

C.1 UNS Electric Substations

Q. Please discuss the UNS Electric Substations in the Mohave Service Area.

A. In the Mohave Service Area, we viewed the following substations: Jagerson, Eastern, Hilltop, West Golden Valley, Griffith, Franconia, North Havasu, Desert Hills, and Clearwater. From a general engineering perspective, the substations are structured fairly similarly, with mostly compression and some welded fitting structures. Equipment types and manufactures of particular components are not the same across the substations. The latter is due to the initial installation of substation facilities by Citizens and subsequent upgrades by UNS Electric. All substations have sufficient space within the substation enclosure for expansion, with a couple of substations currently containing concrete pads for setting future transformers. The additional space, however, is not extraordinary, and should be considered as used and useful. All transformer pads are surrounded by oil-retention trenches filled with coarse, crushed stone. These oil spill enclosures contain trapped drains for oil removal. For the most part, these substations contain concrete cable runs with concrete or steel covers. The substation enclosures are chain-link fencing with vertical slants to help obscure the equipment inside in the rural areas, and textured block walls and caps in the more urban areas around commercial and residential areas.

<u>The Jagerson Substation</u> (Project No. 382061S) was placed in-service December 19, 2007 according to the Company's response to STF 8.1 (STF 1.1). This Substation is a 69 KV/13.2 KV step-down facility currently containing a single 45 MVA transformer. The Jagerson Substation contains a new control room, which UNS Electric claims was necessary because components were no longer available to undertake any repairs to the original control room. The Substation was designed by an engineering group out of Phoenix, and not by TEP personnel.

The Eastern Substation (Project No. 368061S) has been in service since about 2000, with space available for expansion. Modifications to structures and equipment have been on-going with a new transformer and auxiliary equipment to be completed soon. The UNS Electric personnel indicated that this Substation would be fully operational with the new transformer in December 2009. Our observations of the Substation layout agrees with the evolution of the current configurations and plans for the expansion of the facilities.

The Hilltop Substation provides an interconnection with the WAPA 230 KV transmission facilities. There are 2-230 KV/69 KV transformers each at an 80 MVA rating (manufactured by ABB) currently in service, with space available for expansion. There are two (2) WAPA circuits into the Hilltop Substation and three (3) UNS Electric circuits exiting to serve customer loads. UNS Electric personnel indicate very little trouble with this facility except for some breaker maintenance problems.

The West Golden Valley Substation (Project No. 330061S) was placed in-service December 1, 2006 according to the Company's response to STF 8.1 (STF 1.1). This Substation has space available for expansion, and is a TEP design. The West Golden Valley Substation contains a single 40 MVA transformer with an earth and gravel berm oil spillage containment area. This Substation is currently providing electrical power to the Mercator Mine facility (copper and molybdenum) approximately 10 miles away. The majority of the line was paid for by the Mercator Mine, about eight miles. The Company lists its portion of this line (Project No. 311761S) in its response to STF 8.1 (STF 1.1). The line to the Mine is an all steel pole 69 KV line with UNS Electric distribution lines in an underbuild configuration.

The Griffith Substation (Project No. 3270621) has a very large footprint with the majority of the Substation occupied by WAPA. The in-service date for the investment requested in this case is December 21, 2007 according to the Company's response to STF 8.1 (STF 1.1). UNS Electric has a single 84 MVA transformer on site, with room for on additional transformer as system demands may dictate. In this regard, if UNS Electric constructs a Kingman to Havasu line (could be a future development) the available space would be used to set a transformer for the potential 230 KV line. There are currently 3-69 KV UNS Electric circuits from this Substation.

The Franconia Substation is at the terminus of UNS Electric's double circuit structure transmission line (Project No. 331061S) which currently has a single circuit operated at 69 KV. UNS Electric's future plans are to install and operate on the same structures a single circuit 230 KV line to enhance electric network service in the Lake Havasu area. As with UNS Electric's other substations, the Franconia Substation has space available for expansion and placement of another transformer and attendant switch gear.

UNS Electric's North Havasu Substation has a block wall and cap enclosure on the Lake Havasu City side and the chain link with vertical slats fencing on the sides away from the City. This Substation is an interconnect with WAPA's 230 KV system currently with a single 80 MVA transformer. There is currently an open pad for another transformer with implementation of new equipment and interconnection to the network planned by UNS Electric for 2010.

The Lake Havasu City area is expected to continue to increase load in the future. This area has some light commercial loads and is the destination of "snowbirds" starting in

October/November. This tourism has prompted UNS Electric to undertake various improvements and expansions (e.g., Project No. 3270621) in this area to support the system loads.

Load growth in the area, including the construction of a large mall and household supply stores, provided the impetus for UNS Electric to construct the Desert Hills Substation (Project No. 354062S) placed in-service June 30, 2006. Currently, this Substation contains a 44 MVA transformer and is electrically a radial component of the system configuration. UNS Electric plans to loop this Substation in 2010 to enhance support of the electrical loads in this area of the Company's network.

The Clearwater Substation is located in a residential neighborhood with residential houses on all sides. The Substation has a block wall and cap enclosure. While it is in a residential area, the Substation footprint is not lowered (excavated ground configuration) to obscure electrical structures since it is located on a hill and almost all of the houses are below the Substation location. Currently, the Clearwater Substation has two (2) 44.8 MVA transformers (64 KV/13.2 KVA) with firewalls between them. There is also a firewall between the transformers and the control building. The design and on site workmanship was all done by in-house personnel; i.e., UNS Electric personnel.

Q. In general, what is your opinion of the quality and design efficiency of the substations observed?

A. We were satisfied that the quality of construction, the overall design of the stations, reliability aspects, and the capacity of the installed components were in keeping with prudent utility practice and suitable for the expected loadings. Further, provisions for future expansion appear to be adequately provided for in the stations observed.

Q. Are there any other comments as to aspects of the Mohave facilities that you would make?

A. Yes. The 44 MVA transformer installed at the Desert Hills Substation appears to be rated, according to its nameplate, at a 45 degree C. temperature rise. This is very unusual and is either a misprint or TEP (the substation designers per UNS personnel) specified a unique transformer. I have just received a response from the Company to a Data Request I sent regarding this issue. I will address the Company's response in my Surrebuttal Testimony.

Q. Are you requesting that this be addressed by the Company?

A. Yes. Perhaps Company could address this item in subsequent testimony.

C.2 BMGS Facility

Q. Please discuss the generating units and auxiliary equipment at the BMGS Facility.

A. The BMGS Facility consists of 2-45 MW gas-fired generating units with an attendant substation/switchyard located near Kingman. In UNS Electric witness Grant's Direct Testimony of April 30, 2009, he states that BMGS "entered service on May 30, 2008" and is currently owned by UniSource Energy Development Company. It is UNS Electric's proposal to acquire BMGS, which requires approval from the FERC. Mr. Grant states that UNS Electric believes that approval by FERC is likely in a "timely manner," and, therefore, UNS Electric is requesting that the "Commission approve a post-test year adjustment to rate base for the BMGS", at the time of transfer of ownership should that occur.

The BMGS Facility contains Continuous Emission Monitoring systems which are part of the generation equipment package for both units. The Facility layout includes cooling water towers and reservoirs to implement the supply and treatment of necessary water for operation of the units. A connection to a county water source is said to be planned and included as a supplemental source to the ground water wells serving the Facility. The technical personnel at the BMGS Facility indicated to us that the BMGS units could be limited in their hours of operation due to limitations in the water treatment process. Staff submitted a Data Request to clarify the situation as we could consider a limitation in operating duration to affect the value of the station. The Company responded indicating that water availability is not a limitation. However, I recommend that the Company be required to demonstrate adequate water availability at the time of any transfer of BMGS from UniSource Energy Development ("UED") to UNSE.

The week before we visited the BMGS Facility, Unit #1 was taken out of service because of a failure in the turbine section of the Unit. The cause of the failure was evidently a blade failure (breaking) in the 3rd or 4th stage of the turbine section, which precipitated damage to blades in the other turbine stages. Since the Unit had not been dismantled at the time of our visit, a bore scoping of the turbine section indicated that some of the stages had damage to over 50 percent of the blades. In the response to STF 15.3 (received October 20, 2009), the Company states that the estimated time to repair the damage to Unit #1 is 6 to 8 weeks. Additionally, the Company's response states that the "damage is under warrantee and the estimated cost to the Company is zero dollars."

From an engineering perspective, BMGS was properly constructed and should be back to full operational levels once the repairs are made by UED. Both units have been available (with the exception of the recent problem with Unit #1) and have provided generation to the UNS Electric grid since June 2008, under a Purchase Power Agreement. The Company's responses to STF 8.6 and STF 4.3 summarize the net KWH generation and peak net KW for each of the two (2) Units over the period June 2008 through June 2009. In particular, STF 8.6 presents the BMGS monthly KWH generation and peak KW for this period. The following table shows the maximum and minimum outputs for each of the Units as shown in STF 8.6:

	Unit #1		Unit #2	
	KWH Generation	Peak KW	KWH Generation	Peak KW
Maximum	11,960,355 (Dec '08)	47,274 (Dec '08)	13,346,064 (Dec '08)	48,268 (Dec '08)
Minimum	3,198,826 (Jun '09)	43,081 (Sept '08)	1,586,153 (Apr '09)	41,790 (Jun '09)

The response to STF 8.6 shows that there was KWH generation and peak KW output for each Unit in each of the 13 months from June 2008 through June 2009.

The unavailability of BMGS Unit #1 is an unforeseen circumstance that could affect the availability of peaking generation to UNS Electric under its Purchase Power Agreement with UED. That is, the Company has to replace the generation that would have been available from Unit #1 until it can be placed back in-service.

Q. **Are there other aspects of BMGS that you considered during your visit?**

A. Yes. We noted that the general level of maintenance and house keeping appeared to be of very high quality. However, we recommend that Staff re-observe the BMGS facility prior to any purchase of BMGS by UNSE. The control and monitoring system for the unit and auxiliaries and associated software appeared to be well suited to their tasks. We also noted that the software includes a parameter histogram function and that the units are equipped with vibration sensors as well as the expected monitoring for a current modern gas turbine unit.

Q. What was your impression of the common plant items?

A. We observed the substation and connected transmission facilities which are well constructed. The substation is of adequate capacity for the rated output of the units and appears to be well maintained. Responses to our questions as to periodic oil testing and transformer testing were satisfactory. However, the operating personnel appeared to be unsure if thermal scanning of the substation bus and connected lines was to be performed on a regular basis. We would recommend that such be included in the maintenance schedule for the station.

Q. What other aspects did you consider?

A. There appears to be adequate room at the site for the possible expansion of the station to four units of equal capacity. It would appear that with the addition of two more gas turbines and the necessary steam generators and steam turbines that a combined-cycle installation of about 240 MW capacity could be sited on the available area if sufficient water is available. This would include room for the necessary expansion of the substation and transmission. We would consider this possible future expansion of the BMGS site to be a positive consideration in the purchase decision.

Q. What is your impression of the operating efficiency of the BMGS units?

A. The heat rates of the units are reported to have been determined to be 9503 BTU/KWH and 9436 BTU/KWH. These values indicate that the units are operating at the claimed efficiencies and could be considered as efficient sources of periodic peaking power for the UNS Electric system needs.

D. Santa Cruz Service Area

Q. Please describe the characteristics and functions of the facilities observed during your visit to the Santa Cruz Service Area.

A. We visited the Santa Cruz service area on October 7, 2009. Facilities of interest were the addition of Unit #4 turbine at the Valencia Generating Station, the Valencia Substation, the Vail transmission line, the addition of the Motorized Air Break ("MOAB") switch and the Sonoita and Canez Substations. We also discussed general maintenance concerns and service outage response in the Santa Cruz service area with the Lead Superintendent for the Santa Cruz District.

Q. What is your opinion of the Valencia Unit #4?

A. The installation of Unit #4 gas turbine added 19 MW of generating capacity to the Valencia station. This brought the station to a total of 66 MW. The Valencia units are necessary to provide voltage support to the Nogales service area when the load exceeds about 51 MW due to limitations of the supplying transmission line. The line has a rated capacity of 62 MW with the voltage support provided. In addition, Valencia can, if required, supply the Nogales area in the event of an outage of the connected transmission albeit with manual control. Currently, the unit can be dispatched by the Tucson area control facility. This addition was necessary to maintain reliable supply to the Nogales area with a current peak load of about 72 MW and for load growth in the future.

Q. Please continue.

A. Unit #4 has a determined heat rate of about 11,021 BTU/KWH as compared to the existing three older unit's heat rates of about 16,620-16,932 BTU/KWH. This gain in efficiency will result in significant fuel savings when supplying voltage and peaking service to the Nogales area.

Q. What is your opinion of the installation?

A. Our inspection of Unit #4 indicated that it is very well maintained and has operated well since initial operation. However, the unit is currently not capable of a "black start". "Black start" capability refers to the ability of a generating unit to start and deliver proper voltage and frequency to its connected load without connection to or assistance of the area power grid. However, in the case of Unit #4, a black start can be performed by the older units which can then allow Unit #4 to be put on-line. We were informed that a project is planned to provide black start capability for unit #4 in the near future.

Q. What was your impression of the Valencia Generating Station as a whole?

A. The station appears to be in good repair and well maintained. One aspect is that we were informed that there are times when water of suitable quality is required to be transported to the station by truck. While this could be a serious limitation at times when the station is required to serve as the sole source for the area, we were informed that another project is in the planning stages to provide for this water need on a local basis.

Q. What of the Valencia Substation?

A. The installation of a new 50/56 MVA transformer and the upgrading of the bus work has resulted in adequate capacity for the area. The transformer is of dual voltage for future changes in the supply voltage. This Substation is well constructed and appeared to be well maintained.

Q. Are there plans to upgrade the Vail 115 KV transmission line?

A. This line is to be upgraded to 138 KV operation planned for 2012. This voltage increase will allow the threshold for voltage support from Valencia to be increased and to increase the capacity of the line. We are of the opinion that this is a necessary improvement as well as one which should result in future fuel savings.

Q. Were you able to visit the MOAB switch and what was your impression?

A. The motorized air break switch or MOAB is in working order. This switch allows the isolation of the Nogales area at the Canez Substation and can be operated remotely via SCADA. This addition has added needed flexibility to system operation.

Q. Please discuss the substations and distribution network facilities you observed in the Santa Cruz area.

A. Accompanied by an employee of UNS Electric, we observed the <u>Sonoita Substation</u> and the <u>Canez Substation</u>. These Substations are located in a vast development known as Rio Rico, north of Nogales. The Sonoita Substation is a configuration inherited from Citizens with 115 KVA service into the Substation and includes a sizable capacitor bank to increase the power factor in this area.

<u>The Canez Substation</u> is also a Substation inherited from Citizens, with space available for additional transformers and auxiliary equipment as the need arises. UNS Electric is currently anticipating setting another transformer in this Substation. The MOAB switch is located just outside of the chain link fence enclosure of the Canez Substation.

Per our discussions with UNS Electric employees, the distribution network facilities in the area will over time be compatible with the current TEP standards. This will occur as replacements and repairs are needed to distribution lines, structures and equipment. We observed replacements of structures and equipment at several locations in the distribution system.

III. RECOMMENDATIONS TO THE COMMISSION

Q. What recommendations would you offer the Commission based upon the scope of your reviews and field investigations of UNS Electric?

A. We have several recommendations that we offer to the Commission for its consideration regarding UNS Electric.

Our recommendations to the Commission include:

1. The Commission should require an annual report of the distribution indices including a listing of the worst performing circuits and what steps are being taken to mitigate these circuits poor performance by UNS. The report should be separated by service area and by the results for the overall UNS system. Other requirements for this report should conform to those required of Arizona Public Service as described in the current settlement proceedings.

2. The Company states in response to STF 8.1 that they invested approximately $86 million of new plant since the end of the last test year. WML&A reviewed the major plant additions which I discuss in my testimony. Of the plant items we inspected, we found that they were well constructed, functioning at expected levels, and are presently being used for the provision of service to rate payers. Therefore, we recommend that the portion of plant items completed and used and useful at the end of the test year in this proceeding be included in this rate case.

3. Currently, BMGS is owned by UniSource Energy Development ("UED"), however, our inspection of the BMGS facility indicates that the facility is properly constructed and should be back to full operational levels once the repairs are made by UED.

4. At such time if and when UNSE acquires the BMGS, any costs of repair not covered by warranty should be borne by UED and not by UNSE at the time of purchase.

5. If UNSE ultimately acquires BMGS, UNSE should be required to demonstrate to the Commission that there are no limitations due to water availability on the required operations of both Unit #1 and Unit #2.

6. UNS Electric's maintenance scheduling at the BMGS Facility should include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, if it ultimately acquires the facility.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

BACKGROUND & EXPERIENCE PROFILE
W. MICHAEL LEWIS, P.E.
PRESIDENT
W.M. LEWIS & ASSOCIATES, INC.

EDUCATION

1981 - 1988	Master of Business Administration, Ohio University, Athens Office
1971 - 1971	B.S., Electrical Engineering, Ohio State University, Columbus, Ohio

Special Courses:
- Power Circuit Breakers, Ohio State University
- Modern Power System Analysis, University of Wisconsin
- Digital Electronics for Power Application, IEEE
- Modern Methods of Analysis and Protection of Electric Power Systems, IEEE
- Project Management and Planning, University of Wisconsin
- Construction Contract Administration, University of Wisconsin
- High Voltage Testimony, Pennsylvania State
- Lighting Solution and Design, IIT/AEE
- Cogeneration Theory and Design, University of Wisconsin
- Planning, Procurement, and Installation of SCADA Systems, University of Wisconsin, 1989

REGISTRATIONS

Registered Professional Engineer in Kentucky and Ohio
Registered Consultant to the Asian Development Bank, Manila, Philippines

POSITIONS

1979 - Present	President and Manager of Engineering of W.M. Lewis & Associates, Inc.
1974 - 1979	Electric Power Engineer, Goodyear Atomic Corporation (now Martin Marietta Energy Systems)

EXPERIENCE

<u>Summary</u> -- Extensive experience in utility practice, including serving as an expert witness on topics of planning, design, construction, operation, and maintenance of high-voltage transmission lines and facilities, (overhead and underground); high-voltage transformer and circuit breaker loading, operation, and maintenance; working and design clearances on facilities at 230 kV and above and other aspects of utility practice before the State Corporation Commission of Virginia; and on aspects of electric utility design and operation before the Federal Energy Regulatory Commission. Also served as an expert witness in numerous electrical accident litigation concerning interpretation of the NESC, OSHA regulations, and the concept of "Prude nt Utility Practice." Has performed reviews of rural electric utilities in 14 countries.

In addition to experience and expertise in engineering, operation, and code application, prepared operation manuals for client utilities and industries, prepared training curriculum for power operators, trained power operators and linemen, and prepared PM program criteria for utilities and industry. Experienced in HV and EH V testing techniques of transformers and cables and circuit breakers, including OCB and SF_6 designs.

Graduate level studies include concentrated studies of staffing level theory and the use of statistical techniques in electric rate design and preparation of tariffs for electric utilities. Training in safety audits and compliance plans.

ATTACHMENT 2

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.9 Please provide determinations of the reliability indices (Distribution System Indices); i.e., Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)), as well as any other distribution system performance metrics that UNS Electric evaluates for each of 2007, 2008, and to date for 2009. Please state the time threshold used for the calculation of these indices. How do these indices compare with the IEEE standard/guidelines for such indices?

In terms of these indices, please indicate four worst circuits in both the Mohave County and the Santa Cruz County service areas. Please also explain the reasons for the outages and the mitigation measures taken to correct the problems.

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 October 2, 2009

STF 8.9 Please provide determinations of the reliability indices (Distribution System Indices); i.e., Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)), as well as any other distribution system performance metrics that UNS Electric evaluates for each of 2007, 2008, and to date for 2009. Please state the time threshold used for the calculation of these indices. How do these indices compare with the IEEE standard/guidelines for such indices?

In terms of these indices, please indicate four worst circuits in both the Mohave County and the Santa Cruz County service areas. Please also explain the reasons for the outages and the mitigation measures taken to correct the problems.

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

SUPPLEMENTAL RESPONSE: Please see the following tables:

Kingman	2007	2008	2009 - 8/31
SAIFI - All	1.930	2.516	2.816
SAIFI - Clear Weather	1.734	2.010	2.707
SAIFI - MED	1.930	0.985	0.626
CAIDI - All	51.199	100.995	35.716
CAIDI - Clear Weather	49.042	107.932	35.556
CAIDI - MED	51.199	70.994	52.698

Lake Havasu	2007	2008	2009 - 8/31
SAIFI - All	0.912	0.496	0.866
SAIFI - Clear Weather	0.867	0.490	0.656
SAIFI - MED	0.776	0.217	0.661
CAIDI - All	75.327	72.414	40.628
CAIDI - Clear Weather	68.618	72.495	29.630
CAIDI - MED	59.107	71.663	30.163

Santa Cruz	2007	2008	2009 - 8/31
SAIFI - All	1.996	3.713	2.026
SAIFI - Clear Weather	0.977	3.139	1.916
SAIFI - MED	1.881	1.769	1.306
CAIDI - All	84.156	144.393	64.444
CAIDI - Clear Weather	95.566	152.552	63.944
CAIDI - MED	77.866	75.155	60.343

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 October 2, 2009

Mohave	2007	2008	2009 - 8/31
SAIFI - All	1.481	1.604	2.007
SAIFI - Clear Weather	1.357	1.336	1.826
SAIFI - MED	1.189	0.892	1.962
CAIDI - All	59.518	95.879	36.960
CAIDI - Clear Weather	56.044	100.407	34.306
CAIDI - MED	60.631	73.298	24.315

UES	2007	2008	2009 - 8/31
SAIFI - All	1.586	2.029	2.011
SAIFI - Clear Weather	1.280	1.706	1.844
SAIFI - MED	1.586	1.264	1.975
CAIDI - All	65.860	113.506	42.565
CAIDI - Clear Weather	62.214	119.412	40.540
CAIDI - MED	65.860	72.348	32.642

The sustained outage threshold for these indices is 5 minutes. All indices are calculated according to the methods laid out in IEEE 1366-2003.

Indices designated as "All" include all outages that occurred during the indicated year. Indices designated as "Clear Weather" include all outages that occurred during the indicated year, except for those outages caused by storms. Indices designated as Major Event Days "MED" include all outages that occurred during the indicated year, except those outages which occurred on days that were determined to be MED, as defined by IEEE 1366-2003. Due to the availability of properly formatted historical data, MED was calculated using 3 years of historical data for 2007, 4 years for 2008, and 5 years for 2009. All future MED thresholds will be calculated with the rolling 5-year period of historical data.

Indices labeled Kingman, Lake Havasu, and Santa Cruz are calculated with outages from only their respective areas. Mohave indices are calculated by combining the Kingman and Lake Havasu outages. UNS Electric indices are calculated by combining Kingman, Lake Havasu, and Santa Cruz outages.

Indices for Santa Cruz, Kingman, and Lake Havasu are not calculated at a circuit level; therefore, worst circuits, as defined by those criteria, are not available.

RESPONDENT: Lauren Briggs

WITNESS: Thomas A. McKenna

ATTACHMENT 3

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.1 At Page 2 of the Direct Testimony of UNS Electric Witness Michael J. DeConcini, there is the claim that since June 30, 2006 through December 31, 2008 the Company has made capital expenditures of approximately $86 million and that the expenditures are not reflected in current rates. Please provide a list of these capital expenditures by project (and all other projects that are applicable) that represent the post test year rate base adjustment requested by the Company in this case. Include in this response the following:

(a) the identification and description of each project;
(b) the dollar amount of each project;
(c) the date that each project provided in (a) was completed or is expected to be completed; i.e., completed and ready for final testing and inspection prior to placing in-service;
(d) the date that each project provided in response to (a) was placed in-service or is expected to be placed in-service to serve customers;
(e) the date that each project provided in response to (a) was "closed to plant" in UNS Electric's accounting records;
(f) the dollar amount of each project in (a) that was "closed to plant" or the projected dollar amount of each project in (a) at the time it is expected to be "closed to plant"; and,
(g) the separation of the projects in (a) by Generation, Transmission, Distribution, and General Plant categories, as well as other system improvements that are part of the requested rate base adjustment.

RESPONSE: a. – g. Please see UNS Electric's response to STF 1.1 in Staff's first set of data requests.

RESPONDENT: Carl Dabelstein

WITNESS: Michael J. DeConcini

ATTACHMENT 4

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.20 Please provide a listing of all complaints, either formal or informal, made to UNSE by customers that involve claims of poor power quality, including but not limited to , voltage levels, harmonics, "flicker", etc. and a description of UNSE's response. Please include details of all resulting investigations performed by UNSE including what equipment was modified or newly installed as a result of the investigations and if such resolved the complaint.

RESPONSE: Please see the PDF file STF 8.20, Bates Nos. UNSE(0206)08481 to UNSE(0206)08511, on the enclosed CD for all complaints made to UNS Electric that involve claims of poor power quality for the test year (January 1, 2008 to December 31, 2008) through August, 2009.

RESPONDENT: Brenda BeVard

WITNESS: Thomas A. McKenna

STF 8.20

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Brad Morton   **Phone:** (602) 542-0836   **Fax:** (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2 008 - 66025   **Date:** 1/24/2008

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:		
Complaint By:	**Jacquie**	**Svidran**		
Account Name:	Jacquie & Arthur Svidran / Acct# 2787400000		**Home:**	(928) 854-1998
Street:	3120 Gatewood Dr		**Work:**	
City:	Lake Havasu City		**CBR:**	
State:	AZ	Zip: 86404	**is:**	

Utility Company. **Unisource ** Energy Services (UNS)**
Division: Electric
Contact Name: Brenda Bevard   **Contact** (520) 917-2647

Nature of Complaint:

Mrs upset about power outage at her home while she was in residence at another home. Property was aparently out of service for two months and utility never checked to see what the problem was although no energy was used. Customer claims damages but advised ACC does not handle claims. She wants to understand what cause outage and why it was not discovered before they returned to home after two months. *End of Complaint*

Utilities' Response:

January 31, 2008

UNS Electric, Inc. ("UNS Electric") was not made aware of an outage which affected 3120 Gatewood Drive during the time the Svidran's were away. The Svidran's account reflects no usage from September 6, 2007 through December 5 2007. The reads taken within this time were verified reads for three consecutive months which UNS Electric billed the customer on October 8, 2007, November 6, 2007 and December 7, 2007.

UNS Electric does not have record of anyone reporting outages that are also served through the same transformer as the Svidrans.

Please review the UNS Electric Rules and Regulations, Section I, S. 1. a.

S. Continuity of Service

1. The Company shall make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:
   a. Any cause against which the Company could not have foreseen, or made provision for, i.e., force majeure.

Investigator's Comments and Disposition:

Date Completed:

Complaint No 2008 - 66025

ARIZONA CORPORATION COMMISSION
UTILITY COMPLAINT FORM

Investigator: Deb Reagan   **Phone:** (602) 364-0236   **Fax:** (602) 542-2129

Priority: Respond Within Five Days

Complaint **No.** 2 008 - 66552   **Date:** 2/19/2008

Complaint 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	**Jon B.**	**Coppa, M.D.**	
Account Name:	Jon B. Coppa, M.D. / Acct# 5480100000		**Home** (000) 000-0000
Street:	785 San Rafael Valley Road P.O.Box 517		**Work:**
City:	Patagonia		**CBR:**
State:	AZ Zip: 85624		**is:**

Utility Company. **Unisource ** Energy Services (UNS)**
Division: Electric
Contact Name: Tobin Voge   **Contact** (520) 884-3734

Nature of Complaint:
***** E-04204A-06-0783 *****

Customer sent the following e-mail -

From: Jon Coppa [mailto:vcb@groundcontrol.us]
Sent: Friday, February 15, 2008 4:52 PM
To: Mayes-WebEmail; Mundell-Web; Gleason-WebEmail; Hatch-WebEmail; Pierce-Web; Utilities Div - Mailbox
Cc: Marshall Magruder
Subject: Re: Unisource Power Outage and grassland fire. Docket #E-04204A-06-0783

TO: Arizona Corporation Commission

RE: Unisource Power Outage and San Rafael Valley Grassland Fire - February 14 & 15, 2008.

DOCKET #E-04204A-06-0783

Beginning at 10:40AM (February 14, 2008) we experienced repeated severe fluctuations in voltage and I immediately reported this to the Unisource Emergency Call Center. This problem continued until the power went out around 2:30PM on the same date. During this same period there were eye witnesses to a "sparking power pole" near the intersection of the San Rafael Valley Road, Meadow Valley Flat Road and the Apache Road. These witnesses included area ranchers and State employees from the Arizona State Parks facility in the San Rafael Valley, Santa Cruz County. A grass fire erupted at this pole and pushed by winds gusting to 30 and 40 miles per hour, rapidly spread to the head of the San Rafael Valley. This fire consumed several pastures for a large ranch, one pasture slated for grazing in two weeks and another pasture containing many cows with newborn calves. The anticipated claims for damage resulting from this fire could be significant. During the evening the fire had crossed the Canelo Hills and "was headed for Elgin" to the north.

ARIZONA CORPORATION COMMISSION
UTILITY COMPLAINT FORM

We were out of power throughout the region until 1:30PM (February 15, 2008) which represents a total outage of 23 hours. The extended delay in power restoration was due to the U.S. Forest Service not allowing Unisource to proceed with equipment replacement until the Forest Service determined the fire site to be safe for entry.

A prolonged power outage also results in loss of our land line telephone service as the Qwest electronic cabinet at the head of the San Rafael Valley receives its power from the nearby Unisource line.

In the past, the majority of our fires have been due to abandoned campfires from activity by illegal aliens and drug smugglers. Now, our last two major fires have been associated with Unisource equipment failure. The site of ignition for the Willow Fire (2006) and this Willow Springs Fire (2008) are power poles that are within 1/4 mile of one another. Unisource has been much better in communicating their problems to the San Rafael Valley customers and they have been repairing and replacing equipment, but it is obvious that much more has to be done to assure reliable service.

Utilities' Response:

February 25, 2008

The service interruption that affected Mr. Coppa's on February 14, 2008 was associated with a grassland fire in the San Rafael Valley south of Sonoita. UNS Electric, Inc. ("UNS Electric") was not able to restore service to the affected area until the Forest Service authorized access to area where the damaged company facilities were located. Once access was granted UNS Electric replaced a power pole and conductor and reenergized the line. UNS Electric has and will continue to communicate with the San Rafael Valley Homeowners Association regarding service upgrades and or interruptions in the San Rafael area. UNS Electric has been actively upgrading equipment that services the San Rafael area. Some examples of the upgrades include newly installed arresters, fault indicators and spacers. UNS Electric has also conducted extensive tree trimming in the San Rafael area.

Investigator's Comments and Disposition:

E-mailed to Unisource.
End of Comments

Date Completed:

Complaint No 2008 - 66552

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid **Phone:** (602) 542-0848 **Fax:** (602) 542-2129

Priority: Expedite

Complaint No. 2008 70039 **Date:** 7/16/2008

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Annel	Lizarriga	
Account Name:	Annel Lizarriga		Home:(5 20) 839-9532
Street:	483 W. First St.		Work:(0 00) 000-0000
City:	Nogales		CBR:
State:	AZ	Zip: 85621	is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Spanish speaking customer states that she has 2 small children and that they have been without electricity most of the day. She wanted to know when the service will be restored.

Has the problem been found?
How long before electricity will be restored?
Can you contact customer with update?
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

7/16/08 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2008 - 70039

BeVard, Brenda

From:	ACC Complaints - All
Sent:	Monday, July 28, 2008 4:08 PM
To:	'Carmen Madrid'
Subject:	ACC Complaints: Lizarriga, Annel SC UNSE Complaint No. 70039: 05E Quality of Service-Outage/Interruptions (Acct# 5181300000)
Attachments:	rpt_Complaint_EmailPDF.pdf

Carmen,

Please accept my apologies for the delay in our response. This response was inadvertently emailed to another UNS Electric Employee on July 17, 2008. Please review the following for our response.

Thank you,

Brenda

Has the problem been found?
Yes, a 115 kV line lost power due to a broken cross arm which affected the Santa Cruz County area.

How long before electricity will be restored?
Power was restored at 4:07pm on July 16, 2008.

Can you contact customer with update?
Annette Setherley, Administrative Assistant, called and left a voice message for the customer on July 17, 2008 at 9:00am.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Wednesday, July 16, 2008 3:55 PM
To: ACC Complaints - All
Subject: ACC Complaints: Lizarriga, Annel -UNS Electric Complaint No. 70039

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Trish Meeter **Phone:** (602) 542-0622 **Fax:** (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2008 71541 **Date:** 9/18/2008

Complaint Description: 04B Service - Defective Equipment
05D Quality of Service - Field/Premises Visit

	First:	Last:	
Complaint By:	Mary	Jazwin	
Account Name:	Mary Jazwin		Home:(9 28) 757-7968
Street:	2160 E. Hearne Ave.		Work:
City:	Kingman		CBR:
State:	AZ	Zip: 86409	Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

9/17
Customer called stating wiring is bad on the meter. Two company technicians came to the premises and advised her she needed to have new electrical service be put in. She has to force them to do a load test. She received in writing a statement from one of the technicians that " right leg on the meter box is loose and needs a new connection or a new meter box". When calling the supervisor at company, he said the left leg is the responsibilty of the company. Customer states the wires are parallel.

Customer feels this was frivilously handled by the company techs who came out. They did not seem to know anything.

Customer feels that issues in the past may have led up to this recent problem. She has concerns about her home catching fire and being gone in a matter of ten minutes. In the past, (six months) a transformer was not powered downed when there were problems and she wonders if this has something to do with the current problems.
She states she is a lawyer and is not afraid to sue the company. She will not allow anyone to come out and look at things again. She knows she has had an inspector check everything, including electrical in May, 2008. She wants the company to fix this and it had better be tomorrow.

Advised customer of rules regarding responses from utilities and the fact the company may have to send a representative out as part of an investigation.
The meter was not tagged by the techs during the visit.

Questions to the company:

Has customer experienced electrical problems in the recent past?
What was found by company techs on their visit to the property?
Will a new meter need to be provided at the location?

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Please provide the Commission with details to the delivery of service for this customer.
End of Complaint

Utilities' Response:

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Investigator's Comments and Disposition:

9/18
Customer called a second time to go over issues again. She is concerned for her neighbors. She contacted her inspector. She said her ionspector did not know what the UNS rtechs were talking about regarding the problem. Per customer, he stated the area is not accessable to inspection because it is sealed and only the company can open it for inspection.
Customer stated she called 911 in July. 911 person told her to hang up so he could call UNS about the transformer. UNS took a long time to get to the property. The 911 person made it sound urgent.
She stated company is providing gross negligence in service. She will video tape everything.

Advised customer I would attach the additional info to the complaint.
End of Comments

Date Completed:

Complaint No. 2008 - 71541

BeVard, Brenda

From: ACC Complaints - All
Sent: Monday, September 22, 2008 12:40 PM
To: 'tmeeter@azcc.gov'
Subject: ACC Complaints: Jazwin, Mary - UNSE Complaint No. 71541: 04B Service - Defective Equipment (Acct# 2633581613)
Attachments: rpt_Complaint_EmailPDF.pdf; 2160 Hearne Complaint Information 10.9.08.doc

On September 19, 2008, Steve Jacobson, UNS Electric, Inc.'s ("UNS Electric") Construction & Metering Supervisor, and Jim Blem, Working Foreman, met with D. Chapman, Mohave County Building Inspector, at Ms. Jazwin's location on 2160 E Hearne Avenue, Kingman, to investigate her concerns. After reviewing the electrical line and service panel at the location, the Building Inspector told Ms. Jazwin that all the problems were on her side of the service and were her responsibility to repair.

The Mohave County Building Inspector told Mr. Jacobson that he will be sending a letter to the customer giving her five (5) days to have the repairs made, or Mohave County would require her electrical service to be disconnected.

Question: Has the customer experienced electrical problems in the recent past?
Ms. Jazwin requested service with UNS Electric effective June 4, 2008. UNS Electric replaced a bad transformer which serves Ms. Jazwin's property on July 12, 2008. On September 17, 2008 Ms. Jarwin contacted UNS Electric and stated that since the transformer was replaced, someone was hacking into her computer through her electric service. Ms. Jarwin also stated she was getting voltage fluctuations.

Question: What was found by the company technicians on their visit to the property?
On September 17, 2008 a UNS Electric Lineman went to Ms. Jazwin's property to investigate flickering lights and found a loose connection on the line side (customer's side) of the meter. The lineman recommended Ms. Jazwin disconnect service and have an electrical contractor make repairs.

Question: The meter was not tagged by the technicians during the visit?
UNS electric's meter is working properly and will not be replaced.

From: Trish Meeter [mailto:TMeeter@azcc.gov]
Sent: Thursday, September 18, 2008 11:11 AM
To: ACC Complaints - All
Subject: ACC Complaints: Jazwin, Mary - Complaint No. 71541

Please see the attached complaint. It is in PDF format.

MOHAVE COUNTY PLANNING AND ZONING
COMPLAINT FORM

Permits Plus #: ____________________

Address of Alleged Violation: 2160 E Hearne Ave

Legal Description: New Kingman Addition, Unit 11, Block 185, Lot 6, Tract 1104 **T:** 22N **R:** 16W **SEC:** 30

APN: 324-23-206 **Zoning:**________ **Lot Size:** .14 Acres **Allowable OLS:**________

Owner: Mary Ellen Jazwin

Owner Address: 2160 E Hearne Ave Kingman, AZ 86401

Occupant (If Known): Owner

Nature of Complaint: I Received a call from office about a dangerous electrical problem and was told to meet Uni Source at above address. Steve Jacobson from Uni Source informed me that a wire in the electrical panel box was not making complete contact and how they would de-energize the system so it could be repaired but this was the home owner responsibility to make the repair. The owner felt that the expense should be Uni Source's.

I knocked at the door many times with no answer. The Uni Source rep. brought John and I back to the box to see the item in question. We viewed a wire with signs of burn marks, John asked the Uni Source Rep. if he could tighten the lug to secure the wire, the screw did turn but just slightly.

The owner came out and asked who we were are and I informed her who we were and gave her my business card.

She informed me that she had problems with lights flickering and that was why she contacted Uni Source and they informed her to seek an electrician. The owner felt that Uni Source should make the repair. I informed the owner that I was called based on a dangerous condition and that I would gather all information and let her know my recommendation. The owner asked if I could also give her a copy of the same recommendation in writing and I agreed.

The owner asked Uni source to leave her property and asked John & I in to see the receipt she had gotten from Walker Electric and we came in. She could not find the receipt I then informed the owner that I would make my recommendation based on the information available to me and would let her know in writing what would come next.

The owner informed me that she had a load test performed on the panel and it passed. I informed the owner that the wire showed signs of fire and /or arcing and I could not ignore what I had seen. I informed the owner that the County's position was to maintain safety. I asked her for her phone number so that she could be contacted and she proceeded to give me her name, address, phone number and all of her degrees. I informed her all we needed was her number and John wrote the number on a card. We left and I called Mike to inform him of what was happening and said I would come to the office to go over my recommendation with him. I asked if we could have a letter drafted to present to the home owner.

I sent an E- mail to the secretary and CC Mike.

Received By: D. Chapman Date: 9-19-2008

Inspector: DC/JF Inspection Date/Time: 9-19-2008 10:00 am

Status: Letter to be sent to owner with recommendation to have the wire repaired .

__X_ Setup Case **_______ Unfounded**

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez **Phone:** (520) 628-6556 **Fax:** (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2008 - 71205 **Date:** 9/4/2008

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:		
Complaint By:	Solange	Gutierrez		
Account Name:	Solange Gutierrez		Home:	(520) 375-7740
Street:	890 W. Diaz Lane		Work:	
City:	Nogales		CBR:	
State:	AZ Zip: 85621		is:	

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Customer called to complain that her air conditioner and her clothes dryer can not be operated due to a problem with her 220 line feeding her home. Unisource told this customer not to use her 220 line until they can get someone to dig the hole and see what the problem is.
Customer has only been able to use the swamp cooler to her home and wants to know how much longer her 220 line will be out for. Customer said her neighbor had the same problem recently but her work was fixed right away.

Why caused this problem?

Why is Unisource not placing a higher priority in restoring full services to this customer.

Please investigate this matter.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2008 - 71205

BeVard, Brenda

From:	ACC Complaints - All
Sent:	Thursday, September 11, 2008 4:03 PM
To:	'Richard Martinez'
Subject:	ACC Complaints: Gutierrez, Solange - SC UNSE Complaint No. 71205: 04D Service-Not Working (Acct# 1434000000)
Attachments:	rpt_Complaint_EmailPDF.pdf

Tom Hoyt, UNS Electric, Inc.'s ("UNS Electric") Superintendent spoke with Ms. Gutierrez regarding her electric service. Repairs to Ms. Gutierrez's electric service line were completed on Sunday September 7, 2008 and Ms. Gutierrez has been notified.

Mr. Gutierrez appeared happy to know that the line was replaced and thanked Mr. Hoyt for calling her.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Thursday, September 04, 2008 11:43 AM
To: ACC Complaints - All
Subject: ACC Complaints: Gutierrez, Solange - Complaint No. 71205

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez **Phone:** (520) 628-6556 **Fax:** (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2008 - 71197 **Date:** 9/4/2008

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:	
Complaint By:	Montie	McGovern	
Account Name:	Montie McGovern		Home: (520) 761-1578
Street:	2174 W. Frontage Road		Work:
City:	Tubac		CBR:
State:	AZ Zip: 85646		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Customer is upset as he had Unisource (about 20 years ago), called Citizen's Electric at this time, place a line coming off the electric pole which sits about 500 yards away from the Frontage Road to service both his home and his guest house on separate lines. A swimming pool is also serviced by the 220 line that also serves the guest house. This 220 line services both the pool and guest house went out about 3 weeks ago.
When the line was dug up to see what has happened it appears that about 6 years ago when a backhoe hit this line and was repaired with splice as Unisource ran a new wire from that location going back towards the guest house, that this could be the cause of the current outage. Maybe this line has been wet at the splice causing an outage?.

Unisource is now wanting the customer to put a pedestal a few feet away from the electric pole. Customer believes this may be due to the fact that Unisource does not want to take responsibility up to the current point of attachment.

Please investigate the issues concerning the customer's address.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2008 - 71197

BeVard, Brenda

From: ACC Complaints - All

Sent: Thursday, September 11, 2008 3:59 PM

To: 'Richard Martinez'

Subject: ACC Complaints: McGovern, Montie - SC UNSE Complaint No. 71197: 04D Service - Not Working (Acct# 5261510000 and 9448120000)

Attachments: rpt_Complaint_EmailPDF.pdf

On August 19, 2008 Carlos Parra, UNS Electric, Inc.'s ("UNS Electric") Planner received a service order with a request to meet with the customer regarding a damaged service wire.

Mr. Parra met with Mr. McGovern and Teo Cordero, Electrician, to review the underground service to the guest house. The underground service to the guest house is 425' long and it is a separate service from the main house . Both services come from a 10kva pad mount transformer (xfmr). Mr. Parra requested Mr. McGovern and Mr. Cordero to expose the existing trench so that he can inspect the service line.

On August 25, 2008 Mr. McGovern called Mr. Parra and informed him that the trench was exposed and ready for inspection by UNS Electric. Mr. McGovern was out of town when Mr. Parra met with Mr. Cordero for the inspection. Mr. Parra did not find any signs of damage to the conduit in the open trench.

Arturo Lorta, UNS Electric's Senior Planner, met with Mr. McGovern on September 5, 2008 and explained to him that UNS Electric provides the first service at no cost, however additional services to the same lot incurred additional charges.

As of September 9, 2008 Mr. McGovern was unable to provide evidence that Citizens had installed the existing second service and agreed to UNS Electric's terms and conditions for a second service installation.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Thursday, September 04, 2008 11:47 AM
To: ACC Complaints - All
Subject: ACC Complaints: McGovern, Montie - Complaint No. 71197

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez **Phone:** (520) 628-6556 **Fax:** (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 74458 **Date:** 1/9/2009

Complaint Description: 05G Quality of Service - Pressure/Voltage
N/A Not Applicable

	First:	Last:	
Complaint By:	Dara	Mora	
Account Name:	Office Manager-Rio Rico Water Company		**Home:** (000) 000-0000
Street:	Rio Rico		**Work:**
City:	Rio Rico		**CBR:** 520619-1573
State:	AZ	Zip: 85648	**is:**

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Customer said she has been experiencing voltage fluctuations causing the pumps to burn out and breakers to not work on the sewer pump.

The location of this is on Stable Lane.

The sewer location is on Circulo Mercado

***Customer claims that they have been working on these fluctuations on an on-going basis in order for their customers to continue receiving water and sewer service without any interruptions. The breakers continue to trip: therefore, causing temporary outages.

**Also, why is the Emergency Line not working? According to customer she called Unisource on Monday night beginning at around 8 PM and the line was busy as no one answered the phones.
Also, on Wednesday morning at around 6:30 a.m. until around 8:30 a.m. when customer was attempting to reach the Unisource emergency line there was not answer and no one called back

Please investigate
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

BeVard, Brenda

From:	ACC Complaints - All
Sent:	Wednesday, January 21, 2009 4:05 PM
To:	'Richard Martinez'
Subject:	ACC Complaints: Mora, Dara - SC UNSE Complaint No. 74458: 05G Quality of Service - Pressure/Voltage (Acct# 0578500000) Responded 1/21 (Nazar provided an update on 3/17)
Attachments:	rpt_Complaint_EmailPDF.pdf

Tom Hoyt, UNS Electric, Inc. ("UNS Electric") Superintendent, is making arrangements to meet with Ms. Mora regarding UNS Electric's investigation into voltage fluctuations. A recording chart was set to measure the voltage from January 13, 2009 through January 17, 2009. The results confirmed that UNS Electric 's equipment is functioning properly.

Annette Setherley, UNS Electric Office Specialist, spoke with Ms. Mora on January 14, 2009 and explained that on Monday, January 5, 2009 UNS Electric's emergency line received one call from Rio Rico properties at 8:45 pm reporting low/fluctuating usage. Ms. Setherley explained to Ms. Mora that on Monday night the after hours answering service reported they did not have a heavy call volume from the Nogales/Rio Rico area. On Wednesday, January 7, 2009 there was a large outage in Nogales and this may be why Ms. Mora experienced a busy signal. Ms. Mora thanked Ms. Setherley for calling. Ms. Setherley also advised Ms. Mora that she will be hearing from Mr. Hoyt regarding the voltage fluctuations that Rio Rico Water Company is experiencing.

Rio Rico Utilities has two 88 horse power motors each pulling amps when running and pull over 600 amps during start-up. UNS Electric's voltage is approximately 280 when the motor is off, it then dips to 245 during start up, and recovers to approximately 278 during running mode. UNS Electric's investigation indicates that there is a voltage sag and it is due to the heavy amp requirement during motor start-up on the customers side of the meter.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Friday, January 09, 2009 11:55 AM
To: ACC Complaints - All
Subject: ACC Complaints: Mora, Dara - Complaint No. 74458

Please see the attached complaint. It is in PDF format.

BeVard, Brenda

From:	Sandoval, Donovan
Sent:	Tuesday, March 17, 2009 4:24 PM
To:	BeVard, Brenda
Cc:	Couture, David
Subject:	SCUNSE Dora Mora Complaint 74458: Rio Rico Utilities/341 Stable Lane (Update from Nazar)

FYI

-----Original Message-----

From:	Dhahir, Nazar
Sent:	Tuesday, March 17, 2009 11:19 AM
To:	Hoyt, Tom
Cc:	McAdams, Don; Sandoval, Donovan; Rios, Jeremiah; Darmitzel, Bill
Subject:	Re: Rio Rico Utilities

Tom,

Yesterday, Jeremiah and I met with Dara and her boss to discuss their complaint of voltage sags and subsequent motor trips at 341 Stable lane and 1225 Avenida Gloriosa. They claimed that the motors were tripping on phase to phase unbalance exceeding 15%. We presented our charts for 341 Stable lane and showed that their weren't any phase to phase unbalance exceeding 1.6% which is below the recommended ANSI limit of 3%. We also explained that the large magnitude and duration (6 sec) of the voltage sags were due to their motor starts and beyond our control. We recommended that they check their motor undervoltage protection settings for magnitude and time delay to compare it to the actual sags.

As to the overvoltage at 1225 Avenida Gloriosa, they indicated that Unisoruce had adjusted the tabs on the transformer a couple of years ago to help with the sags at this location. They wanted to keep the tabs as is. So there is nothing we need to do here.

Their final concern was that these charts weren't recorded under heavy loading and thus aren't representative of the actual situation. They complained that when a problem occurs they don't get the recorder till a week later when the problem is already gone. We gave them Jeremiah's and my number to call directly when the problem occurs and we will get them a recorder on the same day if there is one available. This seems to make them feel much better and appreciative of our efforts.

Nazar,
3509

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Reg Lopez **Phone:** (520) 628-6555 **Fax:** (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 77437 **Date:** 3/11/2009

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Marcela	Seel	
Account Name:	Marcella Seel		**Home:** (000) 000-0000
Street:	801 S. San Pedro Rd		**Work:**
City:	Golden Valley		**CBR:** Cleopatra525252@aol.com
State:	AZ Zip: 86413		**is:** E-Mail

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

****************************CHAIRMAN MAYES AND COMMISSIONER NEWMAN REFFERRAL************************

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Sunday, March 08, 2009 6:01 PM
To: Newman-Web
Subject: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!!

Saturday Morning the 3-7-09 the Power went OUT again at 7:05 AM till 8:20 AM !!!!!!!!! this time it WASN'T Mother Nature either since they like this for an Excuse every time when it happens !!!!!!!!!!! I called them,was on HOLD for over 20 Minutes what is OUTRAGEOUS !!!!!!!!!!!! this House is only 5 Years old & the Temperature went down to 65 Degrees,i have a Cold from Hell & to get it to warm back up to 70 Degrees took a lot of Electricity also for the Hot Water Tank !!!!!!!!!!!! is this a new way for UniSource to make Money ????? like they aint getting enough now thanks to you all !!!!!!!!!!!!! this keeps on going I'll have UniSource & you all INVESTIGATED !!!!!!!!!! enough is enough !!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

ATTENTION UNISOURCE: PLEASE SEE INVESTIGATORS COMMENTS.

PLEASE CONTACT THE CUSTOMER AND ADDRESS THE REFERENCED POWER OUTAGE AND ANY HISTORY OF OUTAGES IN THE AREA.
End of Complaint

Utilities' Response:

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator's Comments and Disposition:

I replied to the consume with the following:

Dear Consumer:

On behalf of Chairman Mayes and Commissioner Newman, this is in acknowledgement of your e-mail. I would be more than happy to look into the outages that you reference to in your e-mail, but I would need more information from you. If you could provide me with your name, street address with city and zip code, inclusive of other dates and times of past outages, I can initiate an investigation into this matter. If you could please respond by Monday, March 16, 2009, I can commence my investigation. I look forward to your reply.

Sincerely,

Reg Lopez
Public Utilities Consumer Analyst II
Utilities Division-Tucson Office

1-800-535-0148 or (520) 628-6555

3-11 Follow up for 3-17.

3-11 Received the following customerreply:

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Wednesday, March 11, 2009 5:39 PM
To: Reg Lopez
Subject: Re: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!

Mr. Lopez,
my Name: Marcella Seel
801 S. San Pedro Rd
Golden Valley/AZ 86413
Date & Time of Power Outage :
Saturday Morning the 3-7-09 from 7:05 AM till 8:20 AM !!!!

Sincerely,
Marcella Seel

3-12 I repilled to the customer with the following:

Dear Ms. Seel,

Thank you for your reply. I have forwarded this matter to Unisource Energy for their reply regarding the referenced outage and previous outage in your area. Please allow five business days for a reply.

Sincerely,
Reg Lopez
Public Utilities Consumer Analyst II
Utilities Division-Tucson Office

3-12 E-mailed to Unisource @ 10:10 am.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

3-13 Received the following from the customer:

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Friday, March 13, 2009 5:30 PM
To: Reg Lopez
Subject: Re: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!!

Thank you for your Help !!!!!!!!!!!!!!!! M.S
End of Comments

Date Completed:

Complaint No. 2009 - 77437

BeVard, Brenda

From: ACC Complaints - All

Sent: Monday, March 30, 2009 3:30 PM

To: 'Richard Martinez'

Subject: ACC Complaints: Seel, Marcela - UNSE Complaint No. 77437: 05E Quality of Service - Outage/Interruptions (Acct# 2018600000)

Attachments: rpt_Complaint_EmailPDF.pdf

Bill DeJulio, UNS Electric, Inc. ("UNS Electric") General Manager called Mrs. Seel and left a message asking her to return his call regarding her concerns.

Upon review of the trouble orders related to Mrs. Seel service area, UNS Electric believes that the majority of the service interruptions are related to storm activity (lightning). UNS Electric intends to patrol and investigate the lines in the area in question.

Since June 2008, Mrs. Seel has been effected by a number of service interruptions which were related to four (4) transmission interruptions (flicker of lights), six (6) transmission related outages and six (6) distribution related interruptions.

Until March 7, 2009, UNS Electric records indicated that Mrs. Seel had not experienced an interruption to her service since October 7, 2008. The transmission outage on March 7, 2009 was caused by a transformer failing at a customer owned substation.

UNS Electric understands Mrs. Seel 's concerns and frustration and apologizes for any inconveniences caused by the service interruptions.

From: Reg Lopez [mailto:RLopez@azcc.gov]
Sent: Monday, March 23, 2009 1:44 PM
To: ACC Complaints - All
Subject: ACC Complaints: Seel, Marcela - Complaint No. 77437

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid **Phone:** (602) 542-0848 **Fax:** (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2009 80528 **Date:** 7/21/2009

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	John	Brock	
Account Name:	John Brock		**Home:**(0 00) 000-0000
Street:	n/a		**Work:**(0 00) 000-0000
City:	Dolan Springs		**CBR:**
State:	AZ Zip: 00000		**is:**

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

From: Studio [mailto:junostudio@frontiernet.net]
Sent: Monday, July 20, 2009 9:19 AM
To: Utilities Div - Mailbox
Subject: Can You Help Me?

Hello,

I'd like to know if I have any recourse against a power company that provides sub-standard service.

I live in Dolan Springs and had I known that UniSource cannot supply reliable power, I would have never moved here. My power has gone out 8 times just this month (5 times on July 3rd). I call and complain and have even asked to speak to a supervisor but am ignored. I realize sometimes there are weather conditions that may affect service, but many times it's a beautiful day and the power goes out for no apparent reason. If I went back and dug up all the calendar notes in my files for the past 4+ years, I'm sure my power has been interrupted over 50 times. I've had it checked and it's not me - it's UniSource. I'm sure Kingman has better service. Altho it's 35 miles away and I'm out in the boonies, that shouldn't be a factor. I pay for my power on time every month even tho the service is completely unacceptable. Don't I have the right to expect reliable service? Doesn't UniSource have to meet acceptable standards?

I cannot find another company that serves this area, so UniSource must be a monopoly and I suspect their inadequate service may be due to outdated equipment. Aren't they required by law to provide acceptable service? I get excuses all too often that 'a bird flew into a transformer'. Sounds very bogus!

To make it even worse, I'm in the music industry and am trying to record an album. My home is all electric so when my power goes out repeatedly, it interferes with my livelihood and is costing me money. This IS the 21st century and there's no excuse for such bad service. I sunk everything into moving here and buying my home, so it's not a simple solution to move. I've spent about $5,000 for power since I've been here, and I expect (and am entitled to) better service. If it isn't dependable, then what's it worth?

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

I don't want to file a complaint but for now that seems to be the only thing I can do. I spoke to a UniSource supervisor over a year ago, and the service has not improved. After awhile, this becomes hell on your nerves! I cannot live like this.

Your input would be very helpful. Thank you in advance,

John Brock

Is the area where this person lives experiencing an large number of outages?
Has he contacted the company recently to express his situation?
How many times has he contacted UNS regarding service outages?
Is there a problem with the equipment that supplies power to this person?
End of Complaint

Utilities' Response:

.

Investigator's Comments and Disposition:

7/24/09 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2009 - 80528

BeVard, Brenda

From:	ACC Complaints - All
Sent:	Friday, July 31, 2009 3:42 PM
To:	'Carmen Madrid'
Subject:	ACC Complaints: Brock, John - UNSE Complaint No. 80528: 05E Quality of Service - Outage/Interruptions Acct# 7928020000
Attachments:	rpt_Complaint_EmailPDF.pdf

Jim Blem, UNS Electric, Inc. ("UNSE") Construction Supervisor spoke with John Brock on July 28, 2009 regarding outages in his service area. UNSE has had several outages in Mr. Brock's area, which occurred because of different causes. An unreliable system was not the cause for these outages. Mr. Blem reviewed the dates and causes for the outages in question with Mr. Brock. Mr. Brock was pleased that Mr. Blem contacted him and said he understood the reasons for these outages.

Regarding the number of outages experienced in this area; UNSE has recently built a new 69 kV line up Pierce Ferry Road with a 559AAAC feeder circuit on it. Customers who live 35 miles out of town in the "boonies" as referred to in the complaint, are serviced through this line which is 15 miles south of Kingman all the way passed Hoover Dam, in total about 85 miles of line. Although it may be clear weather in one area of the line, a storm or wildlife may be causing a problem further down the line which may result in an outage.

Newly built UNSE facilities have bird protection on it. The older areas do not have bird protection at this time, but when there is scheduled maintenance or an outage, UNSE is putting bird protection on the facilities.

Question: Is the area where this person lives experiencing an large number of outages?
Please refer to the explanation above.

Question: Has he contacted the company recently to express his situation?
Yes, on July 15, 2009.

Question: How many times has he contacted UNS regarding service outages?
9

Question: Is there a problem with the equipment that supplies power to this person?
No.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Friday, July 24, 2009 3:40 PM
To: ACC Complaints - All
Subject: ACC Complaints: Brock, John - Complaint No. 80528

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Deb Reagan **Phone:** (602) 364-0236 **Fax:** (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2009 80829 **Date:** 8/4/2009

Complaint Description: 19A Other - Damages/Claims
01Z Billing - Other

	First:	**Last:**	
Complaint By:	Mavis J.	Sloan	
Account Name:	Mavis J. Sloan #099010000		**Home:**(9 28) 279-6473
Street:	2876 N. Mobile		**Work:**
City:	Golden Valley		**CBR:**
State:	AZ Zip: 86413		**Is:**

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Customer says she has been trying to contact Unisource about a damage claim and was referred to the Commission. Customer says a Unisource outage caused damage to her new big screen tv. Customer wants to speak to someone about this.

Customer also says she has been trying to correct the mailing address on her account. It should be the same as her service address.

Do the Unisource records indicate this customer spoke with a rep regarding the damage claim?
If so, why was she referred to the Commission?
Do the records indicate that customer has called Unisource about the address issue?
When will customer's address be corrected?
What caused the customer's outage that resulted in damage to the tv?
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

E-mailed to Unisource.
End of Comments

BeVard, Brenda

From: ACC Complaints - All

Sent: Thursday, August 06, 2009 10:19 AM

To: 'Deborah Reagan'

Subject: ACC Complaints: Sloan, Mavis J. - UNSE Complaint No. 80829: 19A Other - Damages/Claims Acct# 0990100000

Attachments: rpt_Complaint_EmailPDF.pdf

Anette Setherley, a UNS Electric, Inc. ("UNSE") Representative, spoke with Mavis Sloan on August 5, 2009 regarding her service.

Ms. Setherley explained to Ms. Sloan that UNSE received an official address change request from the County today, August 5, 2009. Ms. Setherley verified with Ms. Sloan that her address has been corrected to 3384 N Mobile Drive in Golden Valley and that her next bill will be mailed to that address.

Ms. Setherley told Ms. Sloan that a company representative from the Damage Claims department would contact her. Ms. Sloan requested that they contact her daughter, Paula Ciesvko who is actually living at the service address. Paula Ciesvko will be added to the account as a contact person as requested by Ms. Sloan.

Pursuant to its Rules and Regulations, UNSE does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

Question: Do the Unisource records indicate this customer spoke with a rep regarding the damage claim?
Yes, on August 4, 2009 Paula Ciesvko called and reported a claim for damages.

Question: If so, why was she referred to the Commission?
The call between the customer and a UNSE Representative on August 4, 2009 was reviewed and the representative did not refer the customer to the Commission.

Question: Do the records indicate that customer has called Unisource about the address issue?
No. The County requested the address change.

Question: When will customer's address be corrected?
The address was corrected on August 5, 2009.

Question: What caused the customer's outage that resulted in damage to the tv?
The customer's service was interrupted on August 4, 2009 due to an equipment malfunction.

From: Deborah Reagan [mailto:DReagan@azcc.gov]
Sent: Tuesday, August 04, 2009 2:16 PM
To: ACC Complaints - All
Subject: ACC Complaints: Sloan, Mavis J. - Complaint No. 80829

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid **Phone:** (602) 542-0848 **Fax:** (602) 542-2129

Priority: Expedite

Complaint No. 2009 80997 **Date:** 8/10/2009

Complaint Description: 05F Quality of Service - Can't Reach Company
N/A Not Applicable

	First:	Last:	
Complaint By:	Fernando	Palomares	
Account Name:	Fernando Palomares		Home:(5 20) 281-2633
Street:	1591 W. Camino Alto		Work:(0 00) 000-0000
City:	Nogales		CBR:
State:	AZ Zip: 85621		is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Consumer states that he has been trying to contact company and can't get through. He states that the lights in his home has been flickering on an off for at least 1.5 hours. He contacted his neighbor and he is experiencing the same thing. He wants to know if the company can inform him what is happening and why.

Please contact consumer and respond to ACC
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

8/10/09 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2009 - 80997

BeVard, Brenda

From: ACC Complaints - All
Sent: Wednesday, August 12, 2009 8:38 AM
To: 'Carmen Madrid'
Subject: ACC Complaints: Palomares, Fernando - SC UNSE Complaint No. 80997: 05F Quality of Service - Can't Reach Company Acct# 4863220000
Attachments: rpt_Complaint_EmailPDF.pdf

Denise Quintero, a UNS Electric, Inc. ("UNSE") Representative, spoke with Fernando Palomares on August 10, 2009 regarding flickering lights at his premise.

Ms. Quintero placed a service order for Mr. Palomares and explained to Mr. Palomares that when he is having trouble with his electricity, such as flickering lights or a power outage, he has the option of contacting UNSE at (877) 837-4968 and select option 1 for an emergency to reach the next available representative. Mr. Palomares thanked Ms. Quintero for calling.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Monday, August 10, 2009 11:54 AM
To: ACC Complaints - All
Subject: ACC Complaints: Palomares, Fernando - Complaint No. 80997

Please see the attached complaint. It is in PDF format.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez **Phone:** (520) 628-6555 **Fax:** (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 81231 **Date:** 8/18/2009

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:	
Complaint By:	Jon	Sandler	
Account Name:	Jon Sandler		**Home:** (520) 377-0205
Street:	1192 Zircon, #1		**Work:**
City:	Rio Rico		**CBR:**
State:	AZ Zip: 85648		**is:**

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard **Contact Phone:** (520) 884-3651

Nature of Complaint:

Customer wants the following questions answered by UNS Energy.

I have 3 things I could use additional help with in getting Unisource to respond-
1) approx. 3 weeks ago I filed a complaint with Unisource after one of their many power outages damaged my stereo amplifier and DVD player. I have followed up twice with Customer Service (what a misnomer that is with UNS) only to be told that they have a record of my calls and someone will call me. No one ever does and it's getting ridiculous. I don't want to wait anymore. In years past, they sent you a form and then sent you a check. This isn't rocket science.

2) at approx. 8:45 am Saturday 8/15/09, the community I live in, Tubac, Az., had another of our power outages. It goes off so often it's crazy. Assuming it was just a normal problem, I did not call it in. When power was not restored by 9:45 , I called "emergency" and was told there had been no other calls so it must be my house. I checked all breakers and called back to say I found no problem and requested immediate service to restore electricity on a day that was to be at least 95 degrees. By 11;40 am, still no one had shown up and when I called in to find out why (again "emergency"), they now said it was community wide but had no idea when power would be restored. At 11:55, I was pulling out of my driveway and a UNS truck went past so I chased him down. He was looking for my house and told me he had not been alerted to a problem until after 11 am! Power was not restored until approx. 4 pm-over 7 hours without electricity! I would like answers to the following questions-
-what caused the outage?
-what took so long to restore power?
-I called at 9:45. Why was the guy not alerted until after 11 am and didn't show until 12? What is the benefit of calling "emergency" if it is not treated like an emergency?
-how can UNS not know when hundreds of homes suddenly go dead and off the grid? What can be done to alert them when there is a problem and not many people call to report it?
-most importantly, why does our power go out so often and what can be done to prevent this from happening so often?

ARIZONA CORPORATION COMMISSION

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3) Power went off again sometime in the afternoon yesterday! I came home to all the clocks flashing again. What caused this?

I would appreciate any help you can be in getting Unisource to respond as a normal business (which had some competition) would/should. I would like my stereo equipment repaired or replaced and I would like to replace my frozen food which sat without electricity for 8 hours on Saturday.

****

Did Risk Management contact this customer since the time he filed for a damage/loss report?

What is causing the outages as described by this customer and what caused this huge delay in restoration of power?

Please contact customer and explain to him the reasoning behind the non-contact with customer and the fact that UNS continues to lose electrical services to its customers.

Please report your findings to the ACC.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2009 - 81231

BeVard, Brenda

From: ACC Complaints - All
Sent: Thursday, August 20, 2009 4:27 PM
To: 'Richard Martinez'
Subject: ACC Complaints: Sandler, Jon - SC UNSE Complaint No. 81231: 04D Service - Not Working Acct# 3680220000
Attachments: rpt_Complaint_EmailPDF.pdf

Patty Tilghman, UNS Electric, Inc. ("UNSE") Claims Analyst spoke with Mr. Sandler on August 19, 2009 and explained that UNSE will not make a payment for damage claims related to a problem the Company could not have reasonably foreseen.

Please refer to UNSE Rules and Regulations, Section No. C (page 66).

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (see Subsection 7.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

Brenda BeVard, UNSE Representative and Angelica Orta-Madrigal, UNSE Distribution Supervisor, spoke with Mr. Sandler on August 20, 2009 regarding outages; a request for a damage claim; and to answer Mr. Sandler's questions and concerns.

Customer's Questions:

What caused the outage?
Bad underground cable.

What took so long to restore power?
Emergency cable had to be installed between the transformer and the overhead line.

Why was the guy not alerted until after 11 am and didn't show until 12? What is the benefit of calling "emergency" if it is not treated like an emergency?
The first no power call UNSE received was at 8:55 am and a crew was dispatched to the area at 9:01 am. UNSE crews do not show up to individual houses (premise), they're routed to where the problem is located with the Company's facilities. It also takes time to locate the problem, especially when the problem is in the underground system. An additional crew was also dispatched to this location at a later time to assist with installation for emergency cable to restore power.

How can UNS not know when hundreds of homes suddenly go dead and off the grid? What can be done to alert them when there is a problem and not many people call to report it?
Generally when hundreds of premises are without power, UNSE receives a high volume of calls to report the outage. In this case, there were sixteen (16) premises without power. The first no power call was reported at 8:55 am. Power was restored for ten (10) premises at 12:41 pm and the remaining six (6) premises were restored at 4:14 pm.

Most importantly, why does our power go out so often and what can be done to prevent this from happening so

often?
There has been a variety of reasons for power outages, some localized, others wide spread. Some outages can be explained others cannot be. Unfortunately, that is the nature of the electric system. It is not until a pattern develops that further investigation is warranted. Nonetheless, the Company understands that our customers are burdened when experienced with any type of outage. UNSE takes outages very serious and works as quickly as possible to restore power.

Power went off again sometime in the afternoon yesterday! I came home to all the clocks flashing again. What caused this?
A temporary outage was required to remove the emergency cable and to repair and install the replacement cable.

Question by the Commission:

Question: What is causing the outages as described by this customer and what caused this huge delay in restoration of power?
These outages that have affected this service area are caused by a variety of reasons like equipment failure, which UNSE may not reasonably foresee, storms or safety hazards. In the case of the outage on August 15, 2009, a bad underground cable needed to be temporarily replaced by an emergency cable installed from the overhead line. This is a time consuming process.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Tuesday, August 18, 2009 11:04 AM
To: ACC Complaints - All
Subject: ACC Complaints: Sandler, Jon - Complaint No. 81231

Please see the attached complaint. It is in PDF format.

ATTACHMENT 5

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.11 Please provide a description of how UNS linemen, maintenance personnel, or "trouble man" personnel are directed to locations of customer complaints and what resources are available to such personnel to identify the distribution system aspects of the problem upon reaching the location of the complaint or outage.

RESPONSE: Work flow for trouble calls:

Santa Cruz County:
Customer calls customer service and reports issue. Between the hours of 7:00 a.m. and 7:00 p.m., the CSR (Customer Service Representative) enters information into Customer Care and Billing ("CC&B"); this data is interfaced into PowerOn, the outage management system. After 7:00 p.m. and before 7:00 a.m., the calls are directed to Kachina, UNS Electric's answering service. Kachina enters the outage data into ICALL (a program to enter trouble calls into PowerOn), an order is then generated by PowerOn and appears in the control window of PowerOn on the dispatchers screen. If this occurs during normal business hours, the dispatcher will make a phone call to the construction supervisor in Santa Cruz County and relay the information. The construction supervisor will then issue the order to a field technician. If the call is during off hours, the dispatcher calls the on call lineman and who responds at that point. Depending on the call, the field technician may call into the dispatch office for more detailed information or may just proceed to the address. If the field technician is required to operate any system devices he will contact the system supervisor for instructions.

Once the issue has been solved or identified, the field technician reports back to the dispatcher. The dispatcher enters data into the PowerOn order. If further work is required, the field technician can have the dispatcher write a work order in STORMS (Severn Trent Operational Resource Management System), the work management system. Also, the dispatcher may call or email the designer for the area if the work that is required is outside the scope of the dispatchers responsibilities.

If there is problem that is monitored thru the EMS (Energy Management System), the system supervisor or the dispatcher will call for a field technician before any customer calls are received. For incidents of this type, the field technician is typically in constant radio contact with the dispatch office. The same protocol is followed once the problem has been solved or identified.

Mohave County – Kingman / Lake Havasu:
Customer calls customer service and reports issue. Between the hours of 7:00 a.m. and 7:00 p.m., the CSR (Customer Service Representative) enters information into customer Care and Billing ("CC&B"); this data is then emailed

automatically into the UESDISP email inbox based on the dispatch priority the CSR places on the the trouble call. After 7:00 p.m. and before 7:00 a.m., the calls are directed to Kachina, UNS Electric's answering service. Kachina enters the outage data into ICALL (a program to enter trouble calls) the trouble call information is then automatically emailed into the UESDISP email inbox. The UniSource System Operator will then enter all the information received by the CSR or Kachina on to an ACCESS program trouble ticket. If this occurs during normal business hours the System Operator will call out the trouble information, on the radio, to the Lake Havasu or Kingman trouble truck lineman. If the call is during off hours the System Operator will then call the on call lineman in that district who will respond at that point. If the lineman is required to operate any system devices he will contact the System Operator for permission and instructions before doing so.

Once the issue has been resolved or identified, the lineman reports back to the System Operator. The System Operator will update the ACCESS program trouble ticket with all of the end result data. If further work is required, the lineman will request the System Operator to forward the information to the district Construction Supervisor or the district engineering group to complete the work or write up a new job request.

If there is a problem that is monitored thru the EMS (Energy Management System), the System Operator will notify the Construction and/or On Call Supervisor in addition to the district trouble truck lineman or on call lineman, via radio or phone, depending on the hour of day, before any customer calls are received. For incidents of this type, the Construction and/or On Call Supervisor in addition to the resonding lineman are typically in constant radio or phone contact the System Operations. The same protocol is followed once the problem has been solved or identified.

RESPONDENT: Thomas Q. Mills III (Santa Cruz) – Bill De Julio (Mohave, Kingman/Lake Havasu) -- Julie McCoy (Lead System Operator, Mohave, Kingman/Lake Havasu)

WITNESS: Thomas A. McKenna

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

DIRECT

TESTIMONY

OF

KENNETH C. ROZEN

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

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EXHIBIT

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

UNS Electric, Inc. seeks Commission approval of various revisions to it Rules and regulations as follows:

- The revised line extension tariff that UNSE submitted pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case, which ordered the elimination of the 400 feet of free footage. Since the Commission approved those revisions in Decision No. 71285 dated October 7, 2009, Staff recommends that UNSE's request that the Commission approve them in this docket is moot.

- Further modifications to the line extension tariff, including the addition of a "Facilities Operation Charge" and a requirement that up-front payments of estimated line extension costs must be Contributions in Aid of Construction ("CIAC"). Staff is of the opinion that the Facilities Operation Charge raises significant issues regarding accounting treatment, rate design, and policy matters which remain unaddressed. Staff opposes implementation of the Facilities Operation charge. Although Staff agrees that the line extension payments should be treated as CIAC, Staff does not believe that the accounting treatment should be specified in the tariff.

- Staff opposes UNSE's proposed revisions that would require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.

- Revisions to the rules governing meter error corrections, which would specify timeframes for repaying and refunding under-billed and over-billed amounts. UNSE's proposed revisions are consistent with Commission rules; Staff has no objection to adding time-frames for repaying and refunding under-billed and over-billed amounts.

- Numerous technical and clarifying revisions throughout the Rules and Regulations. Staff has no objections.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth Rozen. My business address is 14218 N. 43rd Street, Phoenix, Arizona 85032.

Q. By whom are you employed and in what capacity?

A. I am a self-employed consultant under contract with the Utilities Division of the Arizona Corporation Commission. My duties include evaluating various utility applications and reviewing utility tariff filings on behalf of the Utilities Division Staff ("Staff").

Q. As part of your contractual arrangement, did you accept an assignment to review certain matters contained in Docket No. E-04204A-09-0206?

A. Yes.

Q. Please describe your educational background and work experience.

A. Upon receiving a Bachelor of Arts from the University of Arizona in 1977, I was employed as an archaeologist with the Arizona State Museum for sixteen years. In July 1993, the Arizona State Land Department hired me to fill the position of Cultural Resources Manager, which I held until October 2000, when I assumed the duties of the Department's Legislative Liaison. In January 2003, I left the Land Department to become the Legislative Liaison for the Arizona Corporation Commission. After representing the Commission through two regular Legislative Sessions (2003 and 2004), then-Commissioner Mike Gleason hired me as his Policy Advisor in December 2004. I served in that capacity for four years until the end of Commissioner Gleason's last term in December 2008. I retired from service with the State of Arizona in January 2009, and contracted with the Utilities Division the following month.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to provide Staff's recommendations about the revisions UNS Electric, Inc. ("UNSE" or "the Company") is proposing to its Rules and Regulations, as set forth in the Direct Testimony of Thomas A. McKenna. UNSE's redlined version of its Rules and Regulations is presented in Mr. McKenna's Exhibit TAM-2. I will also identify and offer Staff's recommendations about certain other provisions of UNSE's Rules and Regulations, which warrant revision in Staff's opinion.

Q. Please provide an overview of what UNSE's application requests regarding UNSE's Rules and Regulations?

A. In its application, UNSE requests Commission approval of:

- The revised line extension tariff that UNSE filed in Docket No. E-04204A-06-0783 on June 26, 2008 pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case, which in relevant part, ordered the elimination of the 400 feet of free footage;
- Further modifications to the line extension tariff, which were not in the June 26, 2008, proposed revisions, including the addition of a "Facilities Operation Charge;"
- Revisions to service reestablishment and reconnection charges;
- Revisions to the rules governing meter error corrections; and
- Numerous technical and clarifying revisions throughout the Rules and Regulations.

Q. What are the provisions of UNSE's Rules and Regulations, which are not affected by UNSE's proposed changes, that Staff believes warrant revision?

A. They are UNSE's Rules and Regulations pertaining to the content of line extension cost estimates; in particular, Subsections 9.A.3 and 9.B.e.

II. LINE EXTENSION TARIFF REVISIONS

A. Revised Line Extension Tariff Filed Pursuant to Decision No. 70360

Q. Please summarize the proposed tariff revisions that UNSE filed in Docket No. E-04204A-06-0783 on June 26, 2008 pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case.

A. UNSE's June 26, 2008 filing proposed revisions to Sections 2 (Definitions), 6 (Service Lines and Establishments) and 9 (Line Extensions) of the Rules and Regulations. Of these, the revisions to Section 9 respond directly to Decision No. 70360 by eliminating the 400 feet of free footage and related provisions concerning line extensions exceeding 400 feet, including economic feasibility criteria, line extension agreements and refundable construction advances. Proposed revisions to Section 9 add language requiring the customer to pay the estimated cost of constructing line extension up front, and also add a transition period for customers to make plans before the elimination of the free footage. The proposed revisions to Sections 2 and 6 are for conformance with the revisions to Section 9; in Section 2, the definition of "Advance in Aid of Construction" is stricken and the revisions to Section 6 strike language that is inconsistent with the elimination of free footage, while adding language requiring the customer to pay the estimated cost of construction up front.

Q. What is the status of the Commission's consideration of the tariff revisions that UNSE filed on June 26, 2008, pursuant to Decision No. 70360?

A. The Commission approved UNSE's revised Section 6 (Service Lines and Establishments) and Section 9 (Line Extensions) in Decision No. 71285 dated October 7, 2009, a copy of which is attached to my testimony as Exhibit KCR-1. On October 19, 2009, UNSE filed proposed revisions to Sections 6 and 9 to comply with Decision No. 71285. Once they are final, I recommend that the Company file a copy of the revised tariffs in this docket.

Q. Since the Commission approved the revised line extension tariff that UNSE filed as ordered in the last rate case, is UNSE's request that the Commission approve it in this case now moot?

A. Yes, except that it appears that the revision to Section 2, eliminating the definition of "Advance in Aid of Construction," was inadvertently overlooked in the Decision.

Q. Is it Staff's opinion that UNSE would be able to make that revision as a conforming change, without Commission action?

A. Yes, after approving the revisions to Sections 6 and 9, the Decision No. 71285 orders UNSE to make all conforming changes to its Rules and Regulations.[1]

B. Further Modifications to the Line Extension Tariff

Q. What further modifications to its line extension tariff is UNSE proposing, which are not among those approved in Decision No. 71285, and for which UNSE seeks Commission approval in this case?

A. UNSE is proposing two substantive revisions to Section 9, which remain for Commission consideration in this case. First, UNSE proposes to impose a "Facilities Operation Charge" on line extension applicants under certain circumstances[2]. As Mr. McKenna notes, the proposed Facilities Operating Charge is an additional modification from what was submitted on June 26, 2008.[3] Second, UNSE's proposed revisions to Section 9[4] would include a provision in the tariff specifying that up-front payments of estimated line extension constructions costs will be treated as Contributions in Aid of Construction ("CIAC"). Mr. McKenna's testimony states that UNSE is proposing ". . . to require the customer to pay for all construction costs for such extensions as Contributions in Aid of

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1 Decision No. 71285, ordering paragraph at page 4, lines 9 and 10.
2 Proposed Subsections 9.D.2.a.-c, 9.D.4.a.iii, and 9.D.4.b.iii and 9.E; TAM-2 pages 33, 35, 37, 39, 45 and 46.
3 Thomas A. McKenna, Direct Testimony, page 12, lines 1 and 2.
4 Proposed Subsections 9.D.1, 9.D.3.a, 9.D.4.a.i and 9.D.4.b.i; TAM-2 pages 33, 37 and 39.

Construction."[5] While it is true that such payments may be appropriately treated as CIAC, accounting treatment is not something that is typically specified in a tariff. Further, in Decision No. 70360, the Commission did not require the Company to address the appropriate accounting treatment in its line extension tariff revisions.

1. Facilities Operation Charge

Q. What is the Facilities Operation Charge?

A. As described by Mr. McKenna[6], and set forth in proposed Subsections 9.D.2.a.-c., the Facilities Operation Charge is an amount UNSE would charge a line extension applicant if UNSE's projected operating expenses resulting from the distribution line would exceed projected revenues from the new customer or customers on the new distribution line, as determined by UNSE according to the formula set forth in proposed Subsection 9.E ("Economic Feasibility Criteria."). If applicable according to UNSE's determination, the amount of the Facilities Operation Charge would be the difference between UNSE's projected annual operating revenues and operating expenses attributable to the line extension. UNSE would require the customer to pay the Facilities Operation Charge up front as a condition of the line extension agreement and would reevaluate the charge at the customer's request, but no more often than once every 12 months.

Q. What is the Purpose of the Facilities Operation Charge according to UNSE?

A. UNSE's operating expenses associated with the facilities might exceed revenues until the number of new customers grows to a certain level. The purpose of the Facilities Operating Charge would be to cover UNSE's operating expenses to the extent that they exceed revenues from customers using the facilities. Apart from eliminating free footage,

[5] Thomas. A. McKenna, Direct Testimony, page 11, lines 23-25.
[6] Id, page 11, lines 11-27; page 12, lines 1-5.

UNSE views this charge as a further way to ensure that current customers do not pay for facilities necessitated by growth.[7]

Q. Does Staff have any concerns with UNSE's proposed Facilities Operation Charge, and if so, what are they?

A. Yes. Staff has a number of concerns as follows:

1. By applying to line extension customers whose cost to serve is projected to be greater than the average per-customer cost, the Facilities Operation Charge appears to be consistent with a policy of ensuring that growth pay for itself. However, the Facilities Operation Charge fails to account for revenues from those customers whose cost to serve *will be less than* UNSE's average per-customer cost to serve. Staff is therefore concerned that the Facilities Operation Charge would allow the company to collect more revenue than otherwise authorized in rates.

2. Although UNSE views the Facilities Operation Charge as "separate from what is considered CIAC,"[8] Mr. Mckenna's Direct Testimony does not positively identify how UNSE proposes to treat the Facilities Operation Charge for accounting purposes. Without knowing how UNSE intends to treat the Facilities Operation Charge for accounting purposes, the ratemaking implications of approving the charge are unclear.

3. If the Facilities Operation charge were to be booked as revenue, the additional revenues resulting from the charge would have to be offset against savings resulting from customers whose cost to serve is less than the average per-customer cost. Staff is concerned that the method by which UNSE would calculate this offset is unclear.

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[7] Thomas A. McKenna, Direct Testimony page 12, lines 18 through 25
[8] Thomas A. McKenna, Direct Testimony page 12, lines 24 and 25

4. A company's average cost to serve is established for each customer class, but as proposed in Subsection 9.D.2, the Facilities Operation Charge contains no provisions for distinguishing various classes of customers or groups of customers who might be served through a new distribution line. Staff is concerned that the method by which UNSE would calculate the amount of the charge is unclear in that respect.

5. While some of the elements identified in Subsection 9.E as comprising operating expenses, such as depreciation and taxes, appear straightforward, the basis for calculating projected operation and maintenance expense as a percentage of total construction cost for any given extension is unclear.

6. Staff is also concerned that UNSE's proposal to reevaluate the Facilities Operation Charge only at the customer's requests would tend to perpetuate the Charge beyond the time when the number of customers, and therefore operating revenue, are sufficient to cover operating expenses.

7. Finally, as proposed in Subsection 9.2.D, UNSE would have complete autonomy to determine if the Facilities Operation Charge should be imposed on any given applicant using Economic Feasibility Criteria which UNSE alone would calculate on the basis of its own projections. Staff is concerned that this level of autonomy in determining what effectively are prospective customer-specific rates may not be in the public interest.

Q. What is Staff's recommendation regarding the Facilities Operation Charge?

A. In view of the numerous unresolved issues relating to UNSE's proposal to implement the Facilities Operation Charge, Staff opposes the proposal.

2. Accounting Treatment in Tariff

Q. What is Staff's position regarding UNSE's proposal to revise the line extension tariff to specify that payments of line extension construction costs must be CIAC?

A. As I mentioned earlier, accounting treatment is not typically addressed in a tariff. In Arizona Public Services' ("APS") last rate case, for example, the Commission agreed with Staff's recommendation that discussion of the accounting treatment of line extension payments should not be included in the tariff.[9] Staff maintains this recommendation in this case. Regardless of the Commission's determination of the proper accounting treatment, it is inappropriate to specify accounting treatment in the tariff. To do so provides little or no information of practical value to the customer and may have the potential to complicate Commission findings to the contrary under different circumstances in future cases.

C. Line Extension Construction Cost Estimates

Q. What are Staff's concerns with existing provisions in Section 9 relating to line extension construction cost estimates?

A. The estimated cost that a customer is required to pay upfront may not necessarily be sufficiently itemized given the wording of two current provisions in UNSE's Rules and Regulations, Subsections 9.B.1.e and 9.A.3. Subsection 9.B.1.e provides that each line extension agreement must include a cost estimate "to include materials, labor, and other costs as necessary." Similarly, Subsection 9.A.3., states only that UNSE "will provide the Applicant with the estimated costs of extending service." Staff is concerned that this wording allows UNSE to provide a cost estimate consisting essentially of only three estimates; one for aggregate material costs, one for labor and one for aggregate "other" costs. Staff believes that aggregate material costs would not provide the customer with an

[9] Decision No. 70185, Page 2, Finding of Fact 6; Page 5, lines 7 and 8.

adequate basis for evaluating line extension costs, either as proposed in the line extension agreement or in the context of UNSE's comparison between estimated and actual costs after the work is done. In response to Data Requests STF 17.1 and STF 17.2, UNSE filed confidential examples of a cost estimate provided to a line extension applicant pursuant to Subsection 9.A.3 (for the applicant's consideration before accepting) and the corresponding cost estimate included in the line extension agreement, as directed by Subsection 9.B.1.e. Both examples are attached to my Testimony as confidential Exhibit KCR-2. Although the subject line extension entailed over 1,800 feet of overhead distribution line, and may have involved several different types of material costs, only the aggregate materials cost was provided, even though the cost estimate form has a dozen categories for materials. Accordingly, Staff has reason to believe that UNSE's line extension cost estimates are not sufficiently itemized when given to the customer.

Q. What are Staff's recommended revisions to Subsections 9.B.1.e and 9.A.3.?

A. Staff believes that, as a matter of sound regulatory practice, the Company's rules should be clear with regard to the level of itemization the Company is obligated to provide. Therefore, Staff recommends that Subsection 9.B.1.e be revised to provide that line extension agreements must include "A cost estimate to include *itemized* material *costs*, labor and other *itemized* costs as necessary." Staff further recommends that Subsection 9.A.3 be revised to add a new sentence stating that "The estimated costs provided to the applicant will be itemized."

III. SERVICE REESTABLISHMENT AND RECONNECTION CHARGE REVISIONS

Q. What changes to its current service reestablishment and reconnection charges is UNSE proposing?

A. In addition to the amounts currently allowed in Section 14 of its Rules and Regulations, UNSE is proposing to require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.. These additional charges are reflected in new language UNSE seeks to add to the definitions of "Service Reconnection Charge" and "Service Reestablishment Charge" in Section 2[10], in Section 3[11] and also in a footnote in Section 14 ("Statement of Additional Charges")[12].

Q. What is UNSE's rationale for imposing these additional charges changes?

A. UNSE states that service reconnections and reestablishments are significant costs to the Company and that the cost-causers should incur the costs for these services UNSE provides.[13]

Q. Does UNSE's rationale provide sufficient justification for imposing these additional charges?

A. No. Although Staff does not dispute that service reconnection and reestablishment are significant costs to UNSE, the significant charges already authorized in Section 14 are precisely the means by which UNSE is to recover those costs. UNSE's proposal to collect any additional amount for services, such as meter reading and billing, which UNSE did not provide, and for which it therefore incurred no cost, while it was not furnishing electricity to the customer, is groundless.

[10] TAM-2, page 6, Subsection 2.A.48; page 7, Section 2.A.49.
[11] TAM-2 page 14, Subsection 3.E.4
[12] TAM-2 page 68, footnote to Subsections A, B, C and D.
[13] Thomas A. McKenna, Direct Testimony, page 13, lines 5-7.

Q. What is Staff's recommendation regarding UNSE's proposed revisions relating to service reconnection and reestablishment charges?

A. Staff opposes UNSE's proposed revisions relating to service reconnection and reestablishment charges.

IV. METER ERROR CORRECTIONS REVISIONS

Q. What revisions to its meter error correction rules is UNSE proposing?

A. UNSE's proposed revisions to Subsection 11.E (Meter Error Corrections)[14] would add language specifying time frames for repaying and refunding under-billed and over-billed amounts resulting from slow or fast meters, respectively.

Q. Does Staff have any concerns with UNSE's proposed revisions to Subsection 11.E?

A. No. UNSE's proposed revisions to Subsection 11.E are based on and consistent with parallel provisions in Commission Rules[15]

Q. What is Staff's recommendation regarding UNSE's proposed revisions to Subsection 11.E of its Rules and Regulations?

A. Staff has no objections to UNSE's proposed revisions to Subection 11.E.

V. TECHNICAL AND CLARIFYING REVISIONS

Q. What are the technical and clarifying revisions that UNSE is proposing?

A. Technical and clarifying revisions that UNSE is proposing throughout its Rules and Regulations are identified by Section and TAM-2 page number in Exhibit KCR-3 attached to my testimony.

[14] TAM-2, page 54
[15] A.A.C. R-14-2-210, Subsection E, "Meter error corrections"

Q. Does Staff have any concerns with any of the technical and clarifying revisions that UNSE is proposing?

A. No.

VI. SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's Recommendations:

1. Staff opposes UNSE's proposed revisions to Section 9 (Line Extensions) of its Rules and Regulations that would establish the Facilities Operations Charge.

2. Although Staff agrees that the line extension payments should be treated as CIAC, Staff opposes UNSE's proposed revisions to Section 9 that would specify the accounting treatment in the tariff.

3. Staff recommends that Subsections 9.A.3 and 9.B.1. relating to line extension construction cost estimates be revised to require that the estimates include itemized material costs.

4. Staff opposes UNSE's proposed revisions to Sections 2 (Definitions), 3 (Establishment of Service) and 14 (Statement of Additional Charges), that would require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.

5. Staff has no objections to UNSE's revisions to Section 11 (Billing and Collections) which would add time frames for repaying and refunding under-billed and over-billed amounts resulting from slow or fast meters, respectively.

6. Staff has no objections to the numerous technical and clarifying revisions which UNSE is proposing throughout its Rules and Regulations.

Q. Does this conclude your direct testimony?

A. Yes, it does.

KCR-1

BEFORE THE ARIZONA CORPORATI

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

Arizona Corporation Commission
DOCKETED
OCT -7 2009
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IN THE MATTER OF UNS ELECTRIC, INC.'S APPLICATION FOR APPROVAL OF REVISIONS TO ITS LINE EXTENSION TARIFF

DOCKET NO. E-04204A-06-0783

DECISION NO. 71285

ORDER

Open Meeting
September 22 and 23, 2009
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. UNS Electric, Inc. ("UNSE" or "Company") is certificated to provide electric service as a public service corporation in the State of Arizona.

2. Pursuant to Commission Decision No. 70360 issued on May 27, 2008, UNSE filed an application to revise its Rules and Regulations in order to eliminate the free footage allowance contained in its line extension tariff (Section 9).

3. UNSE's current line extension tariff allows for 400 feet of free footage. In other words, customers needing a line extension in excess of 400 feet do not pay for the cost associated with the first 400 feet of the line extension.

4. The proposed tariff revisions also include a transition plan. The plan is as follows:

Transition Period for Elimination of Free Footage

From the effective date of these Rules and Regulations, there is a six (6) month grace period for Customers, developers and subdividers to execute a line extension agreement or receive approval on a new service application from the Company in order to be eligible for the line extension

> policy in effect between August 11, 2003 and May 31, 2008. Those new applicants must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the date of their respective agreement and/or application. In addition, all existing approved line extension agreements and service applications will be grandfathered in under the policy in effect from August 11, 2003 to May 31, 2008. Grandfathered Customers must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the effective date of these Rules and Regulations or they will be subject to the new line extension policy.[1]

5. This proposed language would provide a transition period for customers to make appropriate plans prior to the elimination of the free footage. Dates contained in this passage, however, are outdated and would need to be updated to reflect the timing of the Decision rendered in this matter. Staff has recommended that both references to May 31, 2008 be changed to reflect the date prior to the effective date of the Rules and Regulations approved in the Decision in this matter.

6. The Commission believes it is appropriate for UNSE to outline its plan for raising awareness of the grandfather provisions of the UNSE line extension tariff. Accordingly we believe that UNSE should file by October 23, 2009, as a compliance item to this Decision, a marketing plan detailing UNSE's planned efforts to raise customer awareness of UNSE's new line extension provision to ensure that interested customers are accorded an opportunity to make use of the grandfather provisions within the line extension policy.

7. UNSE's proposed Rules and Regulations includes the following language in the Introduction of Section 9: Line Extensions:

> A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.[2]

8. Staff has recommended that this sentence be removed from the Tariff as it is no longer applicable as a result of the removal of the free footage.

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[1] Application: Proposed Rules and Regulations. Page 37 of 59.
[2] *Ibid.* Page 29 of 59.

9. UNSE's proposed Rules and Regulations includes the following language in Section 9: Line Extensions at item E:

> Construction/Facilities Related Income Taxes
>
> Any federal, state or local income taxes resulting from the receipt of a contribution in aid of construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset *and reflected in the Company's rate base*. (Emphasis added) [3]

10. Staff has recommended removal of the above italicized phrase "and reflected in the Company's rate base" as it is unnecessary for a tariff to specify such a rate base treatment. Removal of the phrase would also make UNSE's line extension tariff consistent with Tucson Electric Power's line extension tariff as established in rate case Decision No. 70628 of December 2008.

11. Staff has recommended that UNSE's proposed changes to Section 9: Line Extensions of UNSE's Rules and Regulations be approved, except for the modifications discussed herein.

12. Certain changes have been made to Section 6: Service Lines and Establishments to conform to the free footage change. Staff has further recommended that UNSE's proposed changes to Section 6: Service Lines and Establishments also be approved to conform to the free footage change.

CONCLUSIONS OF LAW

1. UNS Electric, Inc. is a public service corporation within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over UNS Electric, Inc. and the subject matter of the application.

3. Approval of UNS Electric, Inc.'s revised Rules and Regulations, including a revised Line Extension Tariff, does not constitute a rate increase as contemplated by A.R.S. Section 40-250.

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[3] *Ibid.*

4. The Commission, having reviewed the application and Staff's Memorandum dated September 10, 2009, concludes that it is in the public interest to approve UNS Electric, Inc.'s proposed changes to Section 6: Service Lines and Establishments and Section 9: Line Extensions of its Rules and Regulations, with the modifications discussed herein.

ORDER

IT IS THEREFORE ORDERED that UNS Electric, Inc.'s revised Section 6: Service Lines and Establishments and Section 9: Line Extensions of its Rules and Regulations, including a revised Line Extension Tariff, be and hereby are approved, with the changes discussed herein.

IT IS THEREFORE ORDERED that UNS Electric, Inc. make all conforming changes to its Rules and Regulations.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall docket, as a compliance item in this matter, tariff pages for the revised Rules and Regulations, including a revised Line Extension Tariff, consistent with the terms of this Decision within 15 days from the effective date of this Decision.

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IT IS FURTHER ORDERED that UNS Electric, Inc. shall file by October 23, 2009, as a compliance item to this Decision, a marketing plan detailing its planned efforts to raise customer awareness of the grandfather provisions in UNS Electric, Inc.'s new line extension provision to ensure that interested customers are accorded an opportunity to make use of the grandfather provisions within the line extension policy.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 9th day of October, 2009.

for ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT: ______________________

DISSENT: ______________________

SMO:SPI:lhm\MAS

SERVICE LIST FOR: UNS Electric, Inc.
DOCKET NO. E-04204A-06-0783

Mr. Michael Patten
Roshka, DeWulf & Pattem
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Mr. Phil Dion
UniSource Energy Services
One South Church Avenue, Suite 200
Tucson, Arizona 85702

Mr. Thomas Mumaw
Ms. Deborah A. Scott
Pinnacle West Capital Corp.
Post Office Box 53999, Mail Station 8695
Phoenix, Arizona 85072-3999

Ms. Barbara A. Klemstine
Arizona Public Service Company
Post Office Box 53999, Mail Station 9708
Phoenix, Arizona 85072-3999

Mr. Robert Metli
Snell & Wilmer, L.L.P.
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004-2202

Mr. Marshall Magruder
Post Office Box 1267
Tubac, Arizona 85646-1267

Mr. Daniel Pozefsky
Chief Counsel
RUCO
1110 West Washington, Ste 220
Phoenix, Arizona 85007

Ms. Janice M. Alward
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Mr. Steven M. Olea
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

KCR-2

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206 **UNS ELECTRIC'S RESPONSES TO STAFF'S 17th SET OF DATA REQUESTS**

UNS Electric, Inc. ("UNS Electric" or "Company"), through undersigned counsel, hereby responds to "Staff's Seventeenth Set of Data Requests for UNS Electric" as follows:

Provided herewith are Responses to Data Requests STF 17.1 and STF 17.2.

RESPECTFULLY SUBMITTED this 19th day of October 2009.

ROSHKA DEWULF & PATTEN, PLC

By ______________________
Michael W. Patten
Jason D. Gellman
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
Attorneys for UNS Electric, Inc.

RECEIVED
OCT 1 9 2009
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

Copy of the foregoing hand-delivered/mailed this 19th day of October 2009 to:

Maureen A. Scott, Esq.
Wesley C. Van Cleve, Esq.
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Kenneth Rozen, Consultant
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Alexander Igwe
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Betty Camargo (responses only)
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Daniel W. Pozefsky, Esq.
Residential Utility Consumer Office
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007

William Rigsby
Residential Utility Consumer Office
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007

Ben Johnson Associates, Inc.
3854-2 Killearn Court
Tallahassee, Florida 32309

Philip J. Dion
UniSource Energy Corporation
One South Church, Suite 1820
Tucson, Arizona 85701

By

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S SEVENTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 19, 2009

STF 17.1	Please provide Staff with an example of the estimated costs that the Company provides to Applicants pursuant to Section 9.A.3. of the Company's Rules and Regulations.
RESPONSE:	Please see the attached file STF 17.1 Detailed Cost Letter of Agreement (Confidential), Bates Nos. UNSE(0206)09549 to UNSE(0206)09550, for estimated costs provided to applicants under Section 9.A.3. of the Company's Rules and Regulations. Bates Nos. UNSE(0206)09549 to UNSE(0206)09550 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.
RESPONDENT:	Resal Craven
WITNESS:	Thomas A. McKenna

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S SEVENTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 19, 2009

STF 17.2 Please provide Staff with an example of a cost estimate pursuant to Section 9.B.1.e. of the Company's Rules and Regulations.

RESPONSE: Please see the attached file STF 17. 2 Line Extension Cost Estimate Spreadsheet (Confidential), Bates No. UNSE(0206)09551, for an example of estimated costs pursuant to Section 9.B.1.e. of the Company's Rules and Regulations.

Bates No. UNSE(0206)09551 contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Resal Craven

WITNESS: Thomas A. McKenna

Technical and Clarifying Revisions Proposed by UNSE

Page[16]	Subsection	Revision Proposed by UNSE
2	1.D	Strike "ACC" insert Arizona Corporation Commission"
4	2.A.14	Strike "is" insert "are"
13	3.E.2	Strike "working" insert "business"
14	3.E.4	Insert "Service"
17	4.B.1	Strike "transmit" insert "send"
17	4.B.2	Strike "transmitted" insert "sent"
19	6.A.8	Strike "the" insert "an"
19	6.A.8	Strike "an additional" insert "a"
19	6.A.8	Strike "on file with and approved by the ACC" insert "set forth in the Statement of Additional Charges"
19	6.A.8	Insert "Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the company will have the staffing available for service establishment, reestablishment or reconnection after regular business hours."
46	9.F	Strike "contribution in aid of construction" insert "Contribution in Aid of Construction"

[16] Page numbers in Exhibit TAM-2